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(54) Abstract Title: **Downhole tubular sealing apparatus**

(57) A downhole tubular sealing apparatus and method for sealing a tubular 9 within a second tubular 7 comprises at least one seal 13 associated with an inner tubular 9. A pressure control device 17 is employed to radially expand the tubular member 9 so that it bears against the inner surface of the outer tubular (7, figure 5), which may be a liner or a borehole wall. In a preferred embodiment, the tubular member being expanded undergoes elastic and plastic deformation, and in a particularly preferred embodiment, expansion continues until the outer tubular also suffers deformation. Other embodiments are also disclosed, these being sealing means for an annular space, a method of plugging a downhole tubular, and a method of providing a downhole metal to metal seal.

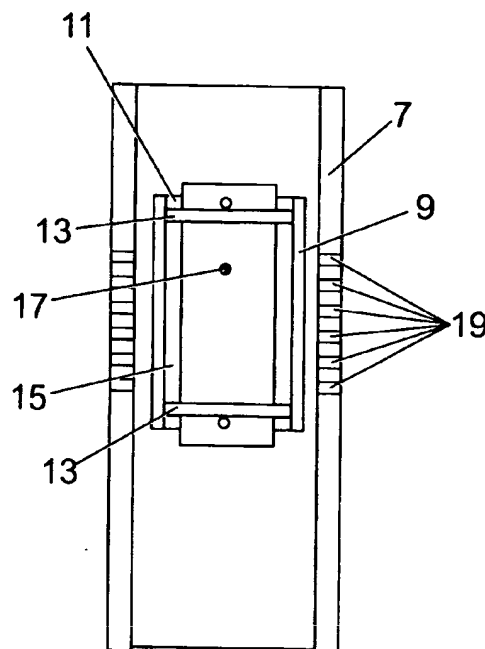


Fig. 2

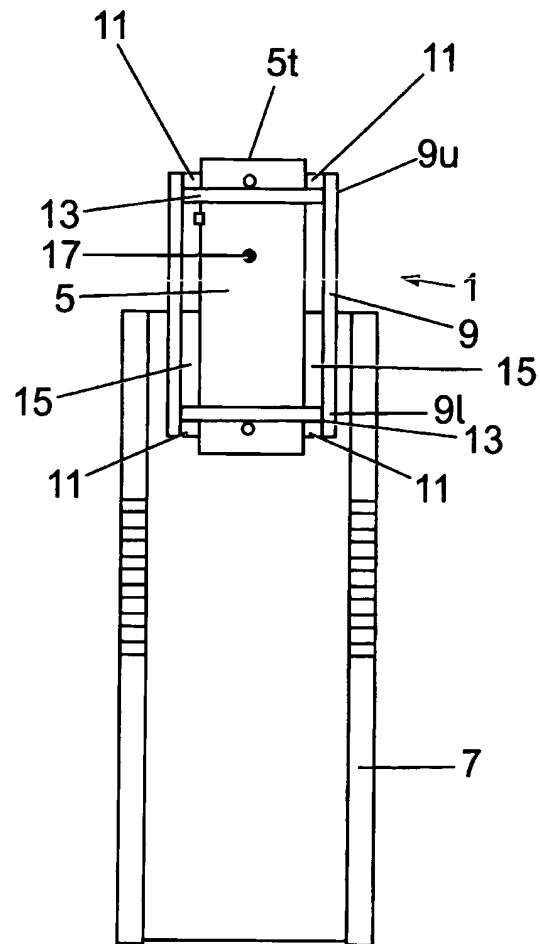


Fig. 1

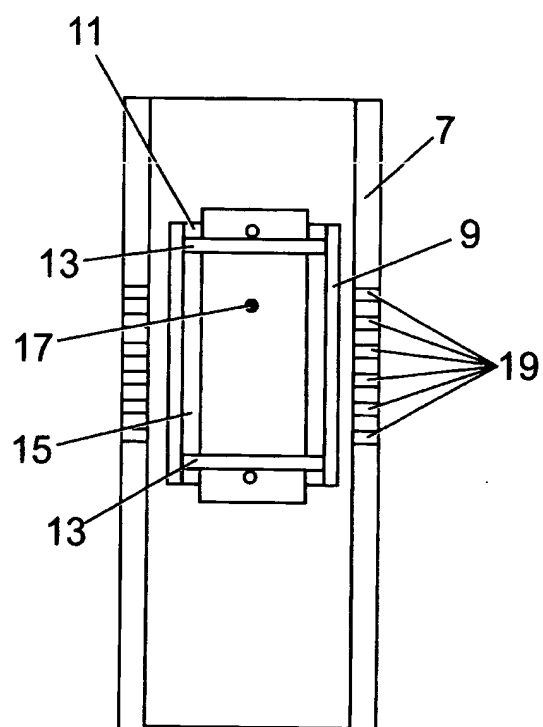


Fig. 2

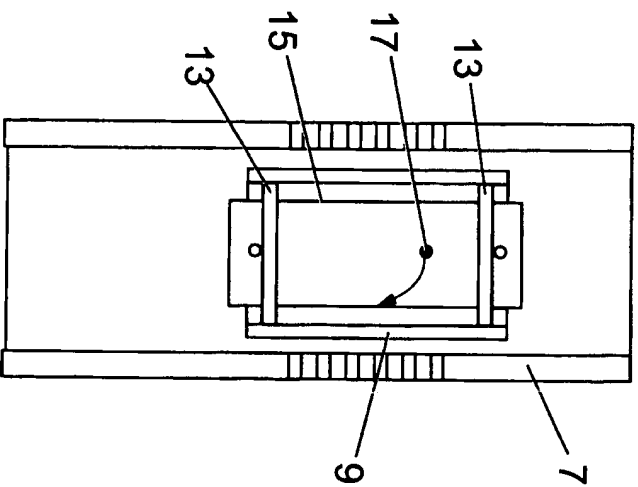


Fig. 3

Setting Pressure

Plastic Expansion
of the Patch

Elastic Expansion of the Patch

Pumped Volume

Fig. 4

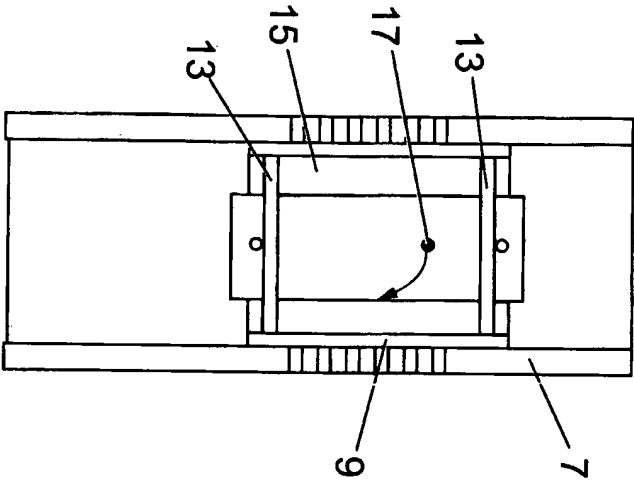


Fig. 5

Setting Pressure

Plastic Expansion
of the Patch

Elastic Expansion of the Patch

Pumped Volume

Fig. 6

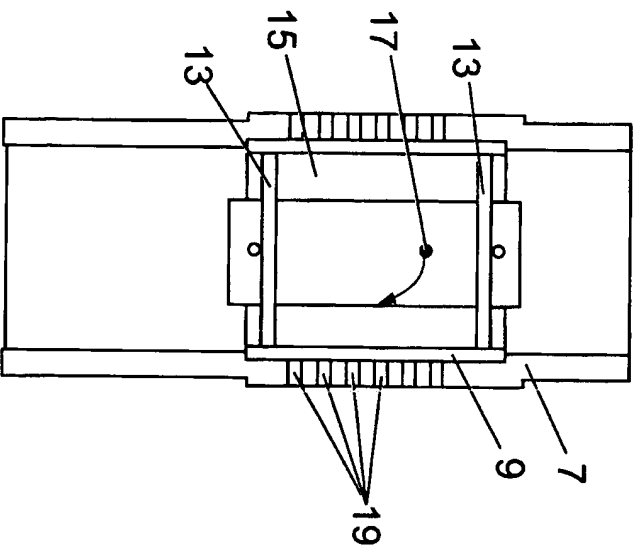


Fig. 7

Setting Pressure

Plastic Expansion
of the Patch

Plastic Expansion of the Patch
Elastic Expansion of the Liner

Elastic Expansion of the Patch

Pumped Volume

Fig. 8

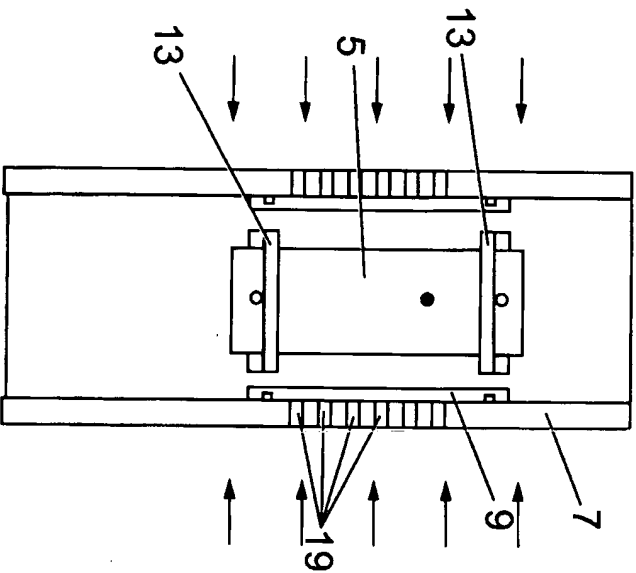


Fig. 9

Setting Pressure

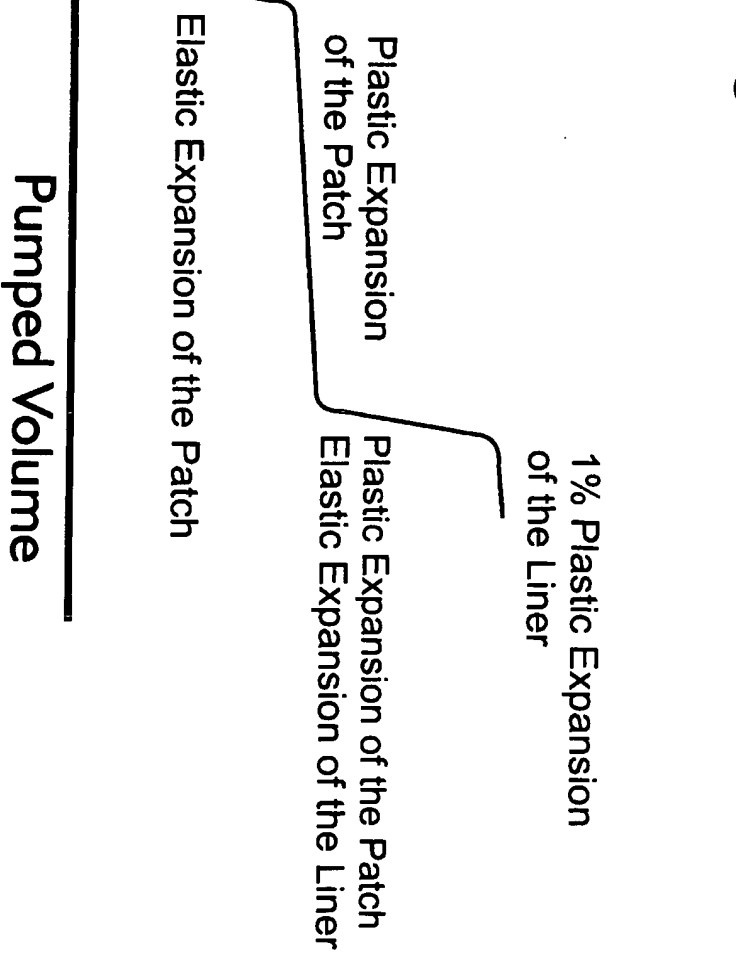


Fig. 10

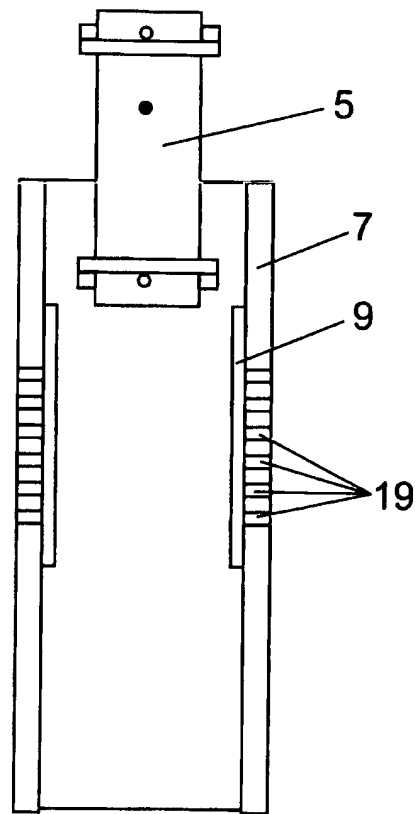


Fig. 11

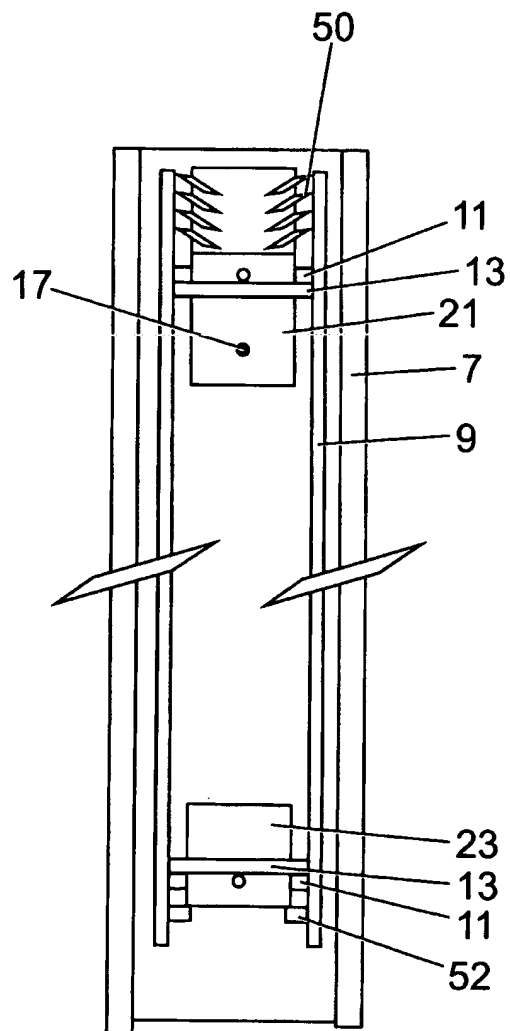


Fig. 12

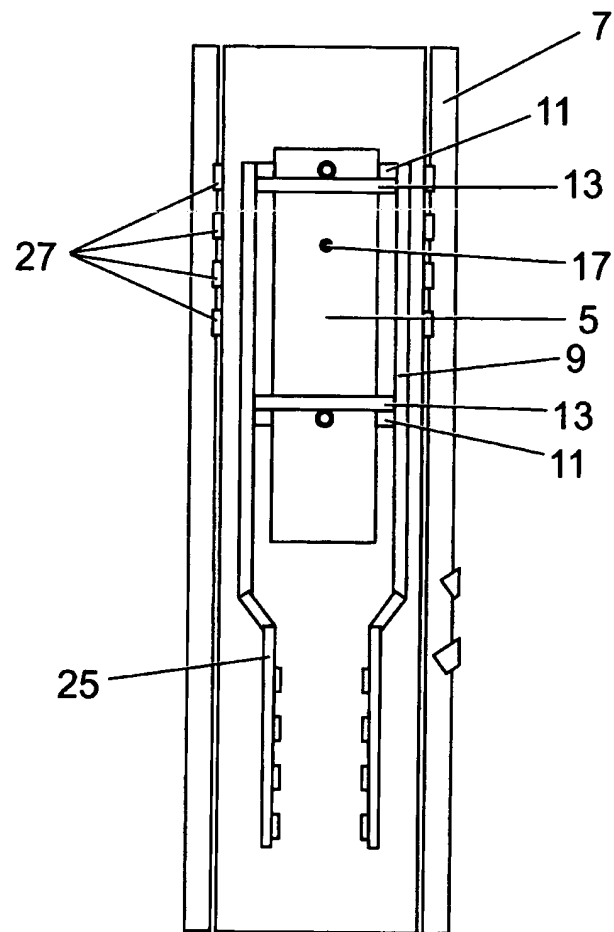


Fig. 13

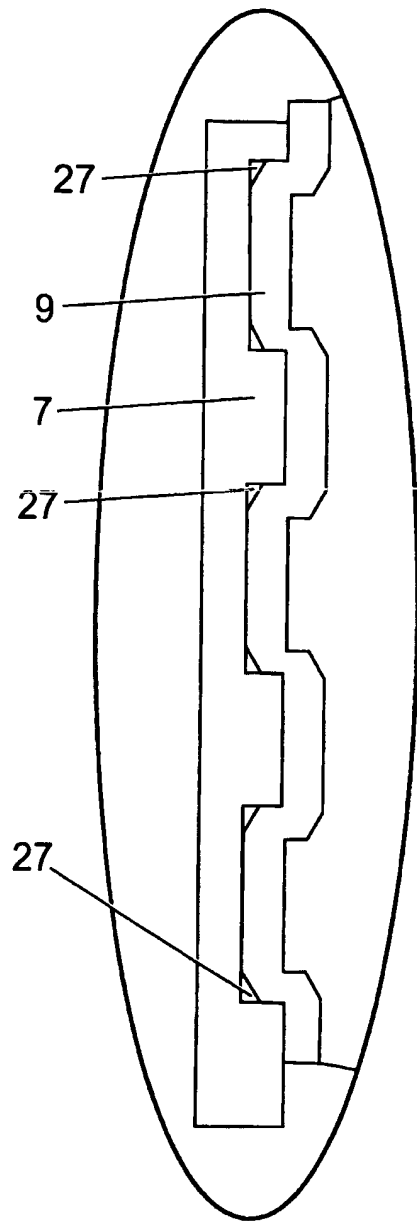


Fig. 14b

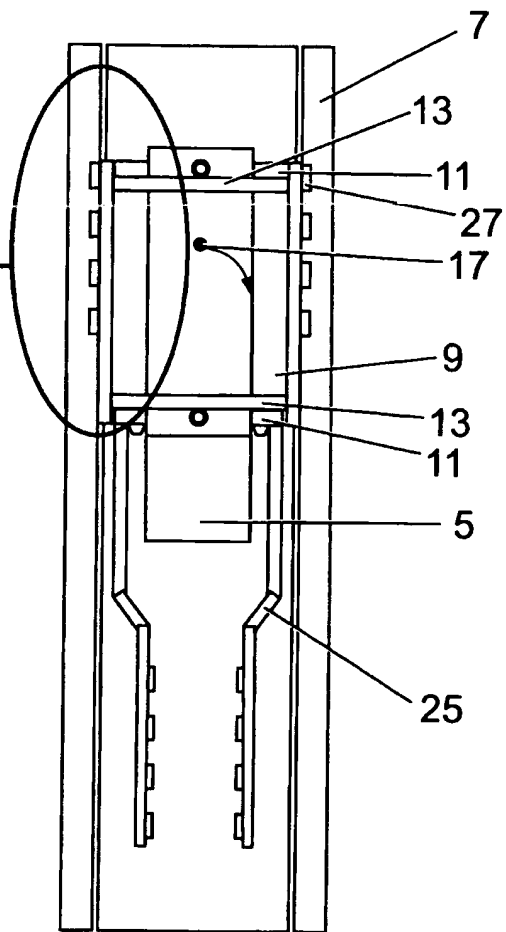


Fig. 14a

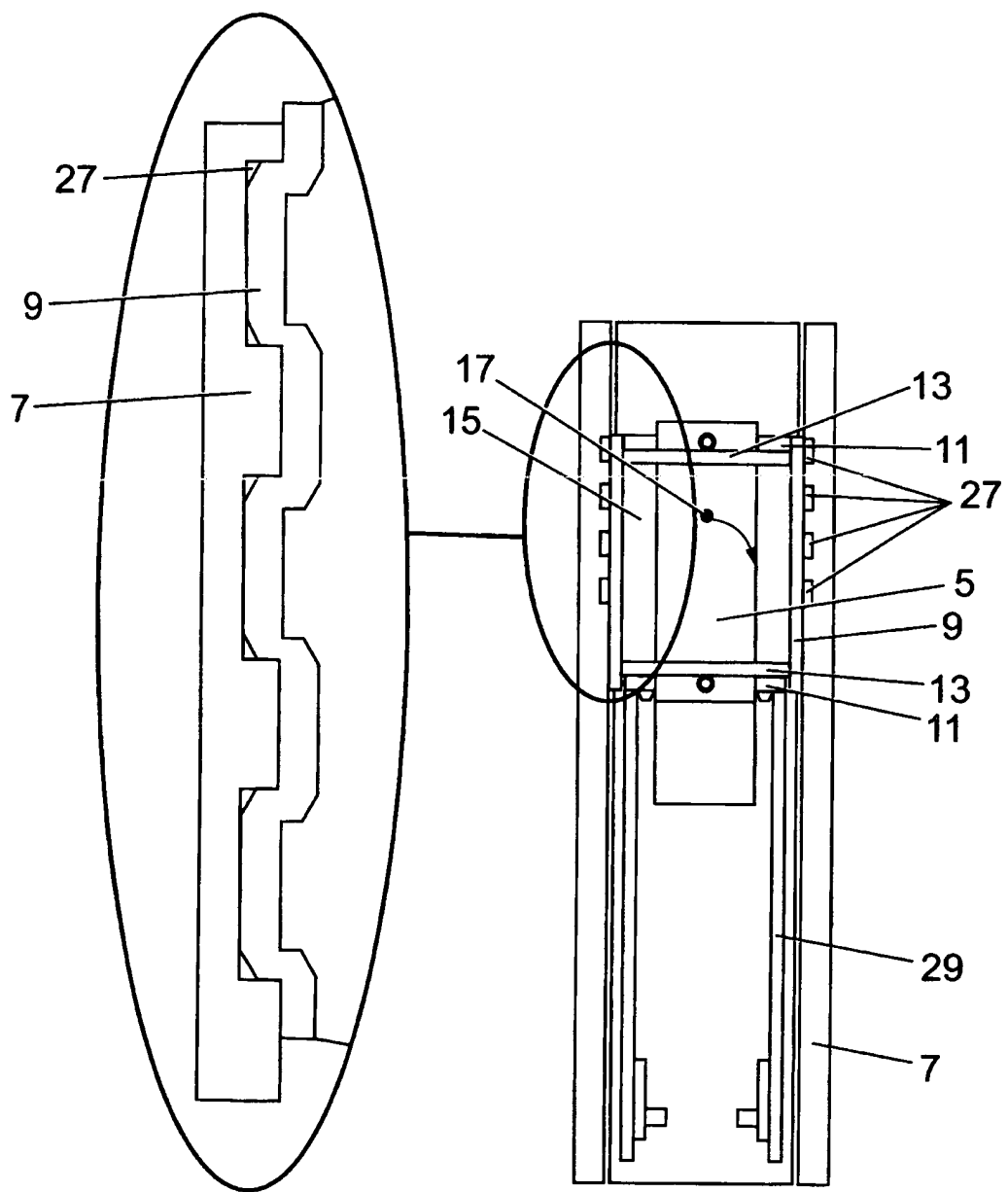


Fig. 15b

Fig. 15a

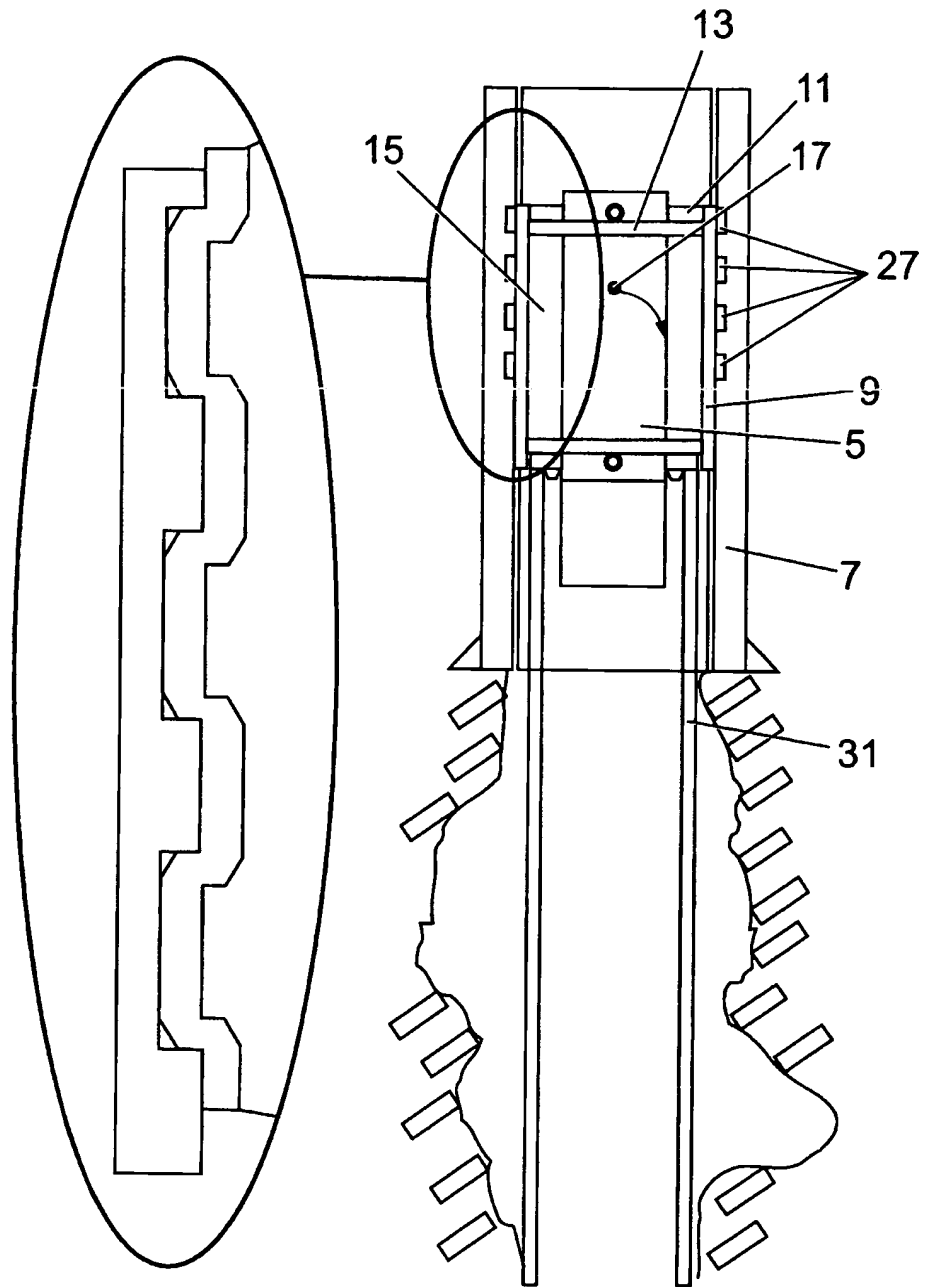


Fig. 16b

Fig. 16a

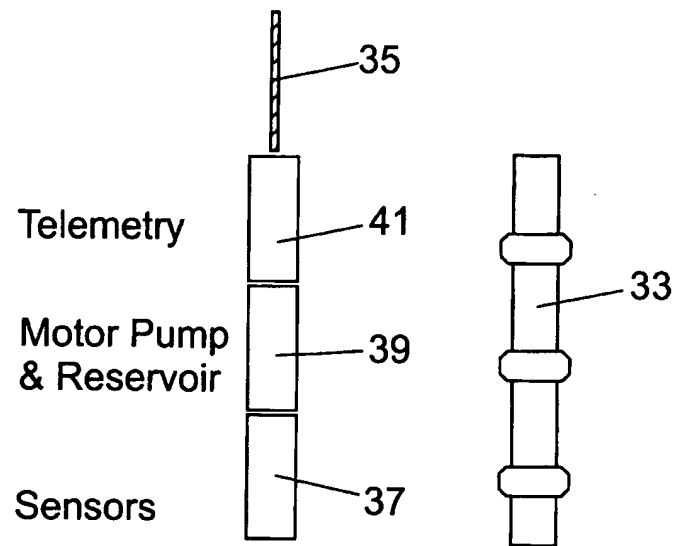


Fig. 17 *Fig. 18*

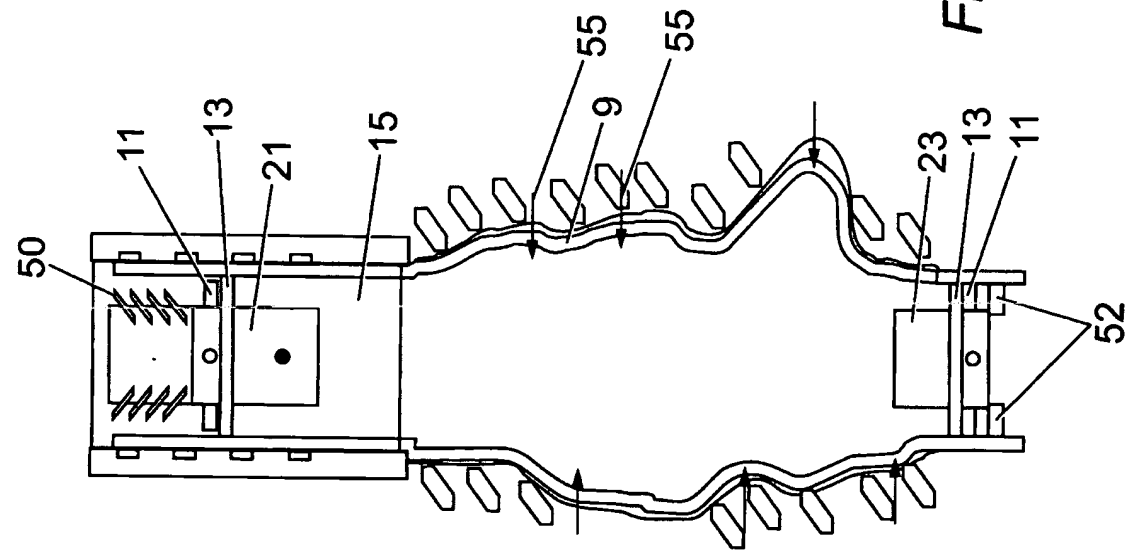


Fig. 19

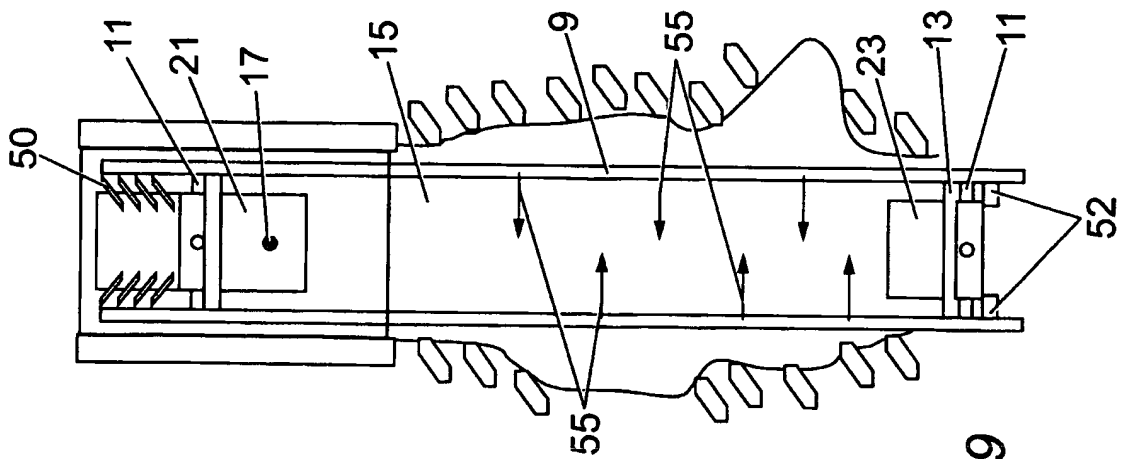


Fig. 20

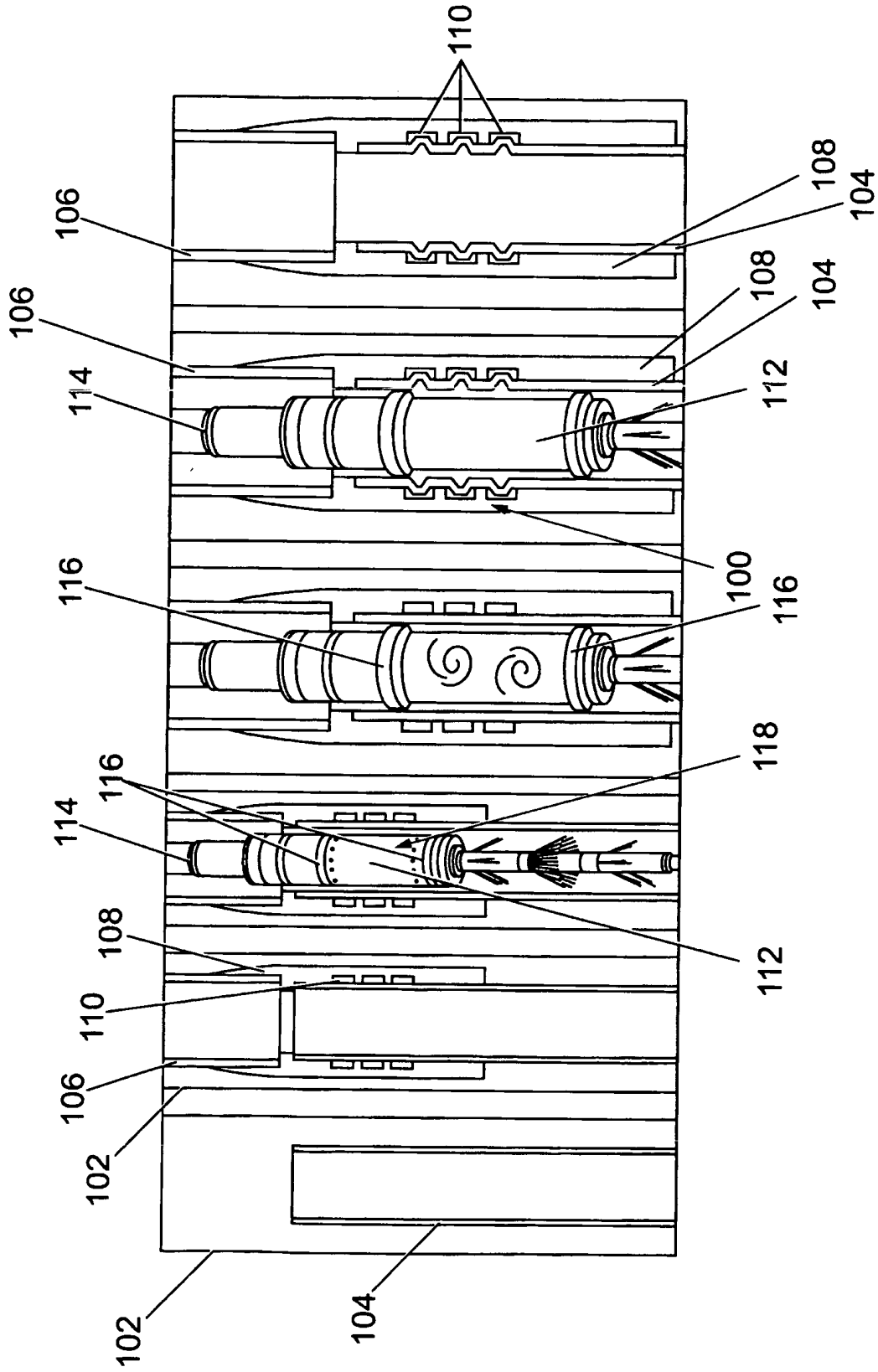


Fig. 21 Fig. 22 Fig. 23 Fig. 24 Fig. 25 Fig. 26

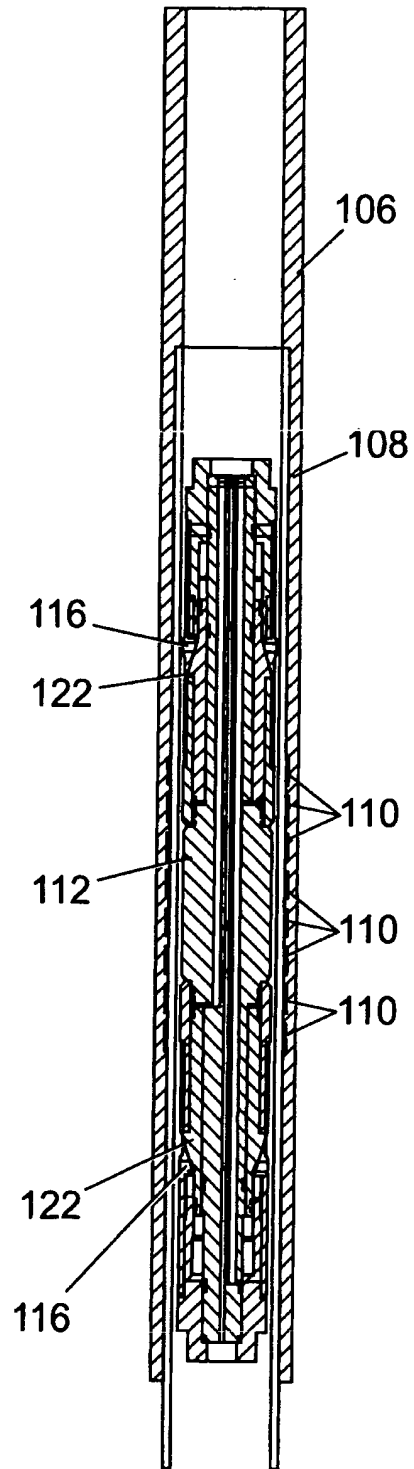


Fig. 27

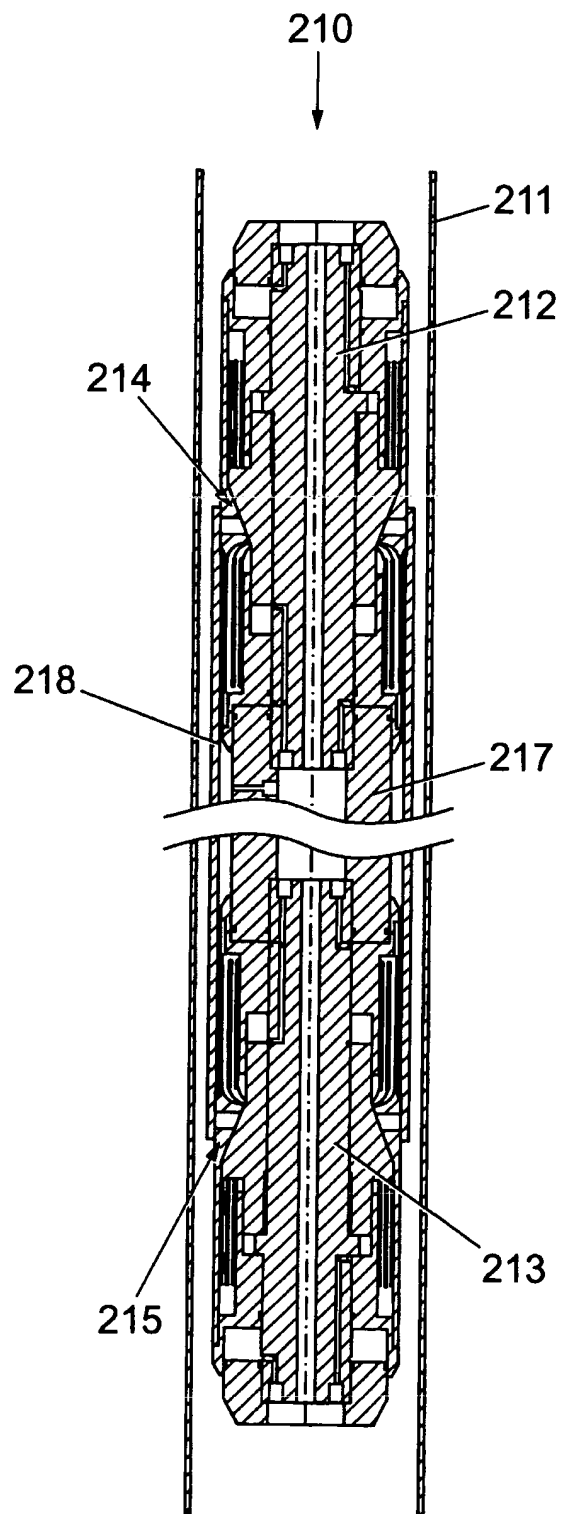


Fig. 28

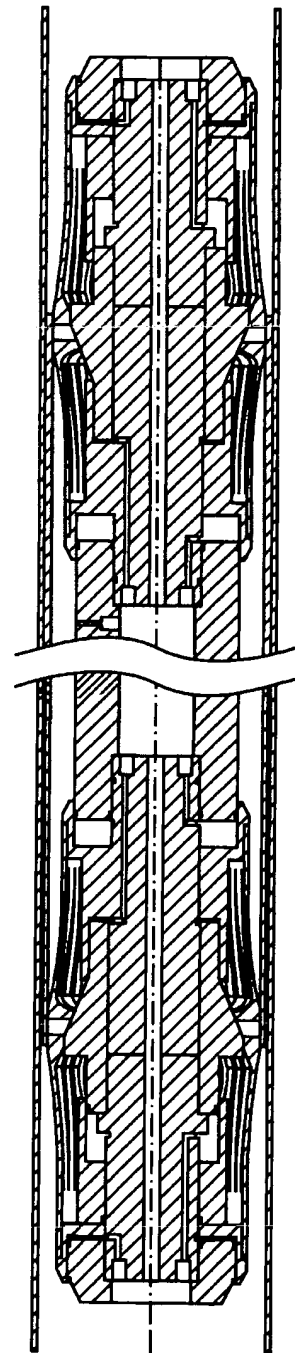


Fig. 29

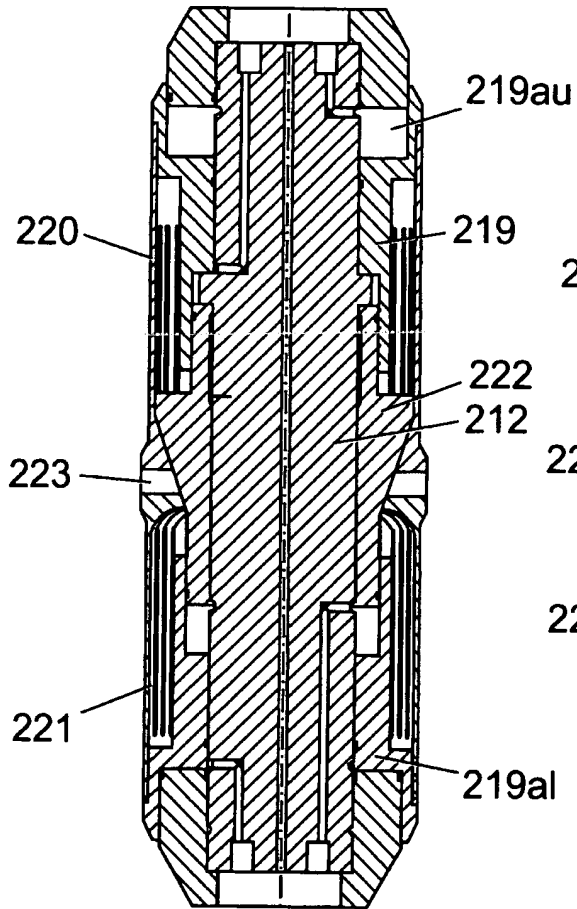


Fig. 30

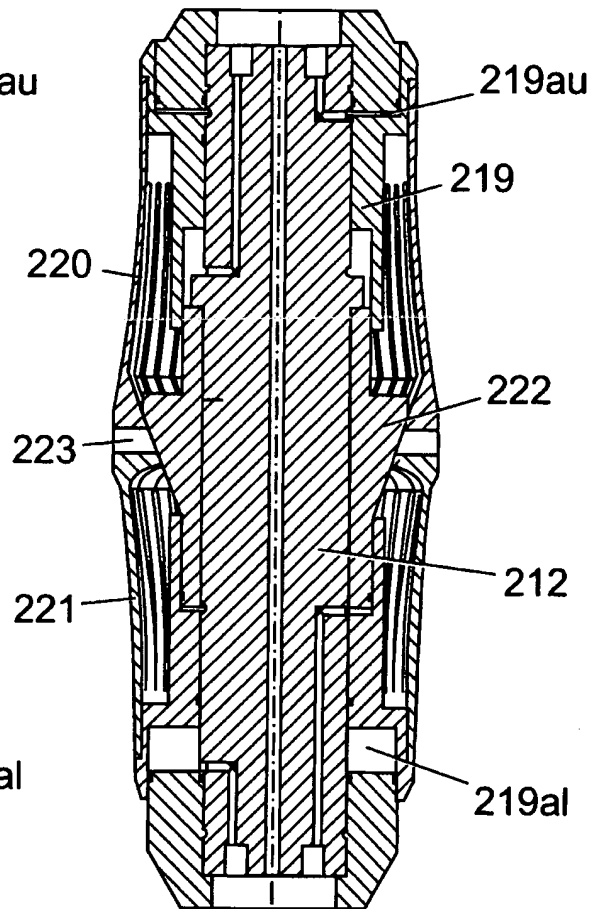


Fig. 31

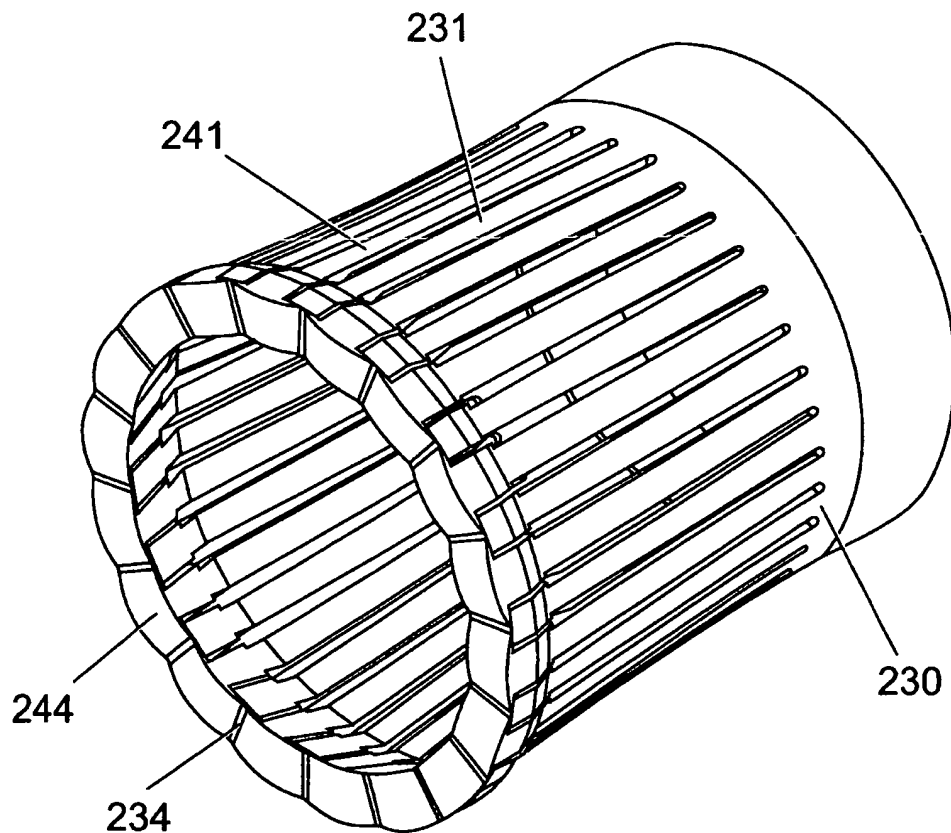


Fig. 32

20 / 20

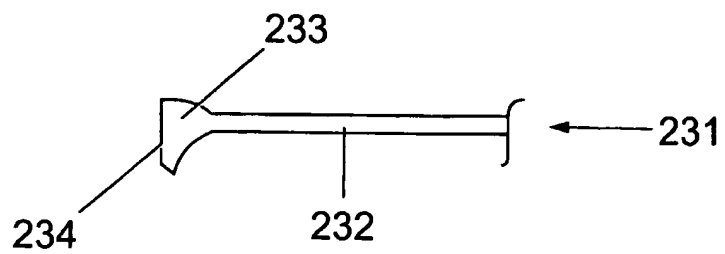


Fig. 33a

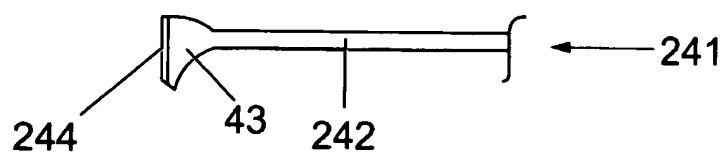


Fig. 33b

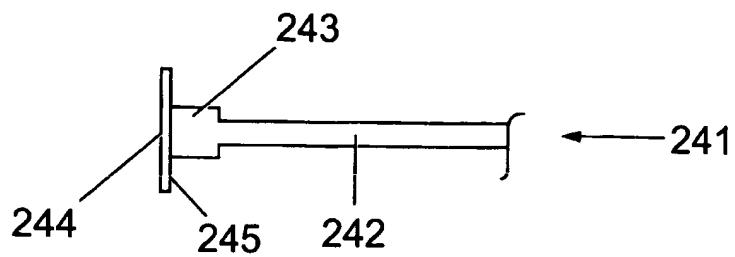


Fig. 33c

1 "Apparatus and Method"

2

3 The present invention relates to an apparatus and
4 method, particularly but not exclusively, for
5 deploying and/or securing a tubular section referred
6 to as a "tubular member" within a liner or borehole.

7

8 Oil or gas wells are conventionally drilled with a
9 drill string at which point the open hole is not
10 lined, hereinafter referred to as a "borehole".
11 After drilling, the oil, water or gas well is
12 typically completed thereafter with a casing or
13 liner and a production tubing, all of which from
14 here on are referred to as a "liner".

15

16 Conventionally, during the drilling, production or
17 workover phase of an oil, water or gas well, and
18 from a first aspect of the present invention, there
19 may be a requirement to provide a patch or temporary
20 casing across an interval, such as a damaged section
21 of liner, or an open hole section of the borehole.

22

1 Additionally, and from a second aspect of the
2 present invention, there may be a requirement to cut
3 a tubular (such as a section of casing) downhole,
4 remove the upper free part and replace it with a new
5 upper length of tubular in an operation know as a
6 "tie back" and in such a situation it is important
7 to obtain a solid metal to metal seal between the
8 lower "old" tubular section and upper "new" tubular
9 section.

10

11 Additionally, from a third aspect, the present
12 invention relates to a seal packer for subterranean
13 wells which can be used to isolate two zones in an
14 annular space of such wells, or to join two tubes
15 together, etc.

16

17 The use of radially expandable packers is well known
18 in the art. These packers, or seals, are frequently
19 used to do maintenance in areas over the packer, or
20 to seal off a particular formation, for example a
21 water producing zone of the well.

22

23 Generally, there are two types of packers, the first
24 type is inflatable rubber packers and the second
25 type is compact rubber packers. The two types have
26 different characteristics when it comes to the
27 expansion ability and temperature and pressure
28 tolerance. Today, even more well environments have
29 high temperature and pressure, and it is a challenge
30 to develop reliable equipment for such environments.
31 The prior art have some disadvantages, for example
32 the high temperature and high pressure can cause

1 extruding of the packer. Consequently, this may
2 result in a leakage. Another disadvantage is that
3 some packers after compression in well bores with
4 extreme temperatures and pressures will not function
5 properly, for example the relaxation of the packer
6 can work poorly.

7

8 There have been several attempts to solve the
9 disadvantages mentioned above.

10

11 GB Patent Publication No 2296520A describes oil/gas
12 well tools related to a sealing/packing tool which
13 provides a pressure/fluid barrier. It provides a
14 downhole tool comprising at least one ring with
15 petaloid extensions, said ring being disposed about
16 a longitudinal axis of the said tool, and means for
17 controllably deforming said petaloid extensions such
18 that said extensions may be controllably moved in
19 use. Said controllable movement may cause the
20 extensions to be brought into close proximity with
21 an inner surface of a conduit. Said tool may
22 further comprise an elastically deformable packing
23 element. The extensions are expanded by a wedge
24 surface on the ring and help to centre the tool in
25 the conduit. The extensions may also be arranged to
26 act as anti extrusion means for the packing element.

27

28 US Patent Publication No 5226492 describes a packer
29 for sealing an annular space comprising a deformable
30 hollow metallic sleeve having an inner cavity which
31 has an open end. The sleeve is preferably cone
32 shaped. An expandable member is disposed within the

1 inner cavity. A wedge member is located in close
2 proximity to the expandable member, and serves to
3 transmit a compressive force to the expandable
4 member to obtain the desired radial expansion of the
5 sleeve. The compression causes the expandable
6 member to be forced around the outside of the wedge
7 member and forms a first seal between the expandable
8 member and an annular production casing. The rim of
9 the metallic sleeve is also in contact with the
10 production casing and accordingly a second seal is
11 formed. Further, the metallic sleeve may comprise
12 one or more slots at desired intervals to facilitate
13 the deformation of the metallic sleeve.
14 Additionally, a seal obtained using an additional
15 band provides improved sealing due to an additional
16 seal formed between the additional band and the
17 inner wall of the production casing.

18

19 The main object of the third aspect of the invention
20 is to provide a device which avoids the
21 disadvantages of the prior art. The device
22 according to the invention should be able to seal an
23 annular tube, and also to join two tubes together,
24 in a so-called swage process. Consequently, this
25 requires considerable forces to be applied, which
26 again demand packers with special properties.

27

28 According to a first aspect of the present
29 invention, there is provided a method of securing a
30 tubular member within a liner or borehole of a well,
31 the method comprising:-

1 inserting the tubular member into the borehole;
2 and

3 increasing the pressure within the tubular
4 member between a pair of seal means associated with
5 the tubular member, such that the pressure increase
6 causes the tubular member to move radially outwardly
7 to bear against the inner surface of the liner or
8 borehole.

9
10 According to the first aspect of the present
11 invention, there is also provided an apparatus for
12 securing a tubular member within a liner or
13 borehole, the apparatus comprising at least one seal
14 means associated with the tubular member, and a
15 pressure control means operable to increase the
16 pressure within the tubular member, such that
17 operation of the pressure control means causes the
18 tubular member to move radially outwardly to bear
19 against the inner surface of the liner or borehole
20 wall.

21
22 Preferably, the pressure control means is also
23 operable to monitor the pressure within the tubular
24 member. Typically, the pressure control means is
25 also operable to control the pressure within the
26 tubular member.

27
28 Typically, the apparatus comprises a pair of seal
29 means, and more preferably comprises a pair of
30 sealing devices in accordance with the third aspect
31 of the present invention. Typically, the pressure
32 is preferably increased within the tubular member

1 between the pair of seal means. The pressure may be
2 provided by a hydraulic fluid.

3

4 The tubular member may be coupled to an apparatus
5 for use within the borehole, such as a nipple
6 profile, seal assy, seal bore receptacle, temporary
7 liner/tubing section or other apparatus.

8

9 Typically, the method of the first aspect further
10 comprises inserting the tubular member into the
11 liner or borehole to the required depth. Conveyance
12 of the apparatus may be by way of wireline, coil
13 tubing or drill pipe.

14

15 The tubular member is typically in the form of a
16 patch, and is preferably moved radially outwardly
17 such that the tubular member undergoes elastic
18 deformation and also plastic deformation. The
19 tubular member or patch member is preferably formed
20 from a suitable metal material, such as steel or an
21 alloy material, and may be provided with a coating
22 such as an elastomeric coating and/or a non-uniform
23 outer surface such as a ribbed, grooved or other
24 form of surface, in order to increase the
25 effectiveness of the seal created by the tubular
26 member when it is secured to the liner or borehole.

27

28 Typically, the apparatus further comprises a body
29 located within the tubular member, and preferably
30 located co-axially within the tubular member.
31 Preferably, the pair of seal means are mounted upon
32 the body and may be energised to seal against the

1 inner surface of the tubular member. Typically, the
2 body comprises a port to permit the flow of fluid
3 into, and preferably to allow the flow of fluid out
4 of, a chamber which is preferably defined by the
5 outer surface of the body, inner surface of the
6 tubular member, and inner faces of the pair of seal
7 means. Preferably, the seal means are in the form
8 of packer elements or segments, and which may be
9 provided with back-up rings, which may be formed
10 from steel. The body may contain
11 hydraulic/electrical systems to control the flow of
12 fluid, pressure and/or activate/de-activate the
13 seals.

14
15 Typically, the pressure, flow volume, depth and
16 diameter of the tubular at any given time will be
17 monitored and recorded by either downhole
18 instrumentation or surface instrumentation.

19
20 Preferably, the tubular member is releasably coupled
21 to the body by means of a coupling means, which may
22 comprise retractable pins or slips. The retractable
23 pins or slips are preferably initially locked to the
24 tubular member, and typically, after operation of
25 the apparatus such that the tubular member has
26 reached the desired level of expansion, the pins or
27 slips are retracted inwardly toward the body, such
28 that the engagement between the pins or slips and
29 the tubular member is broken.

30
31 The tubular member is typically moved radially
32 outwardly by the pressure to bear against the inner

1 surface of the liner or borehole wall. Optionally,
2 the tubular member or liner may be provided with a
3 surface that facilitates providing engagement
4 between the liner and the tubular member, and the
5 said surface may comprise one or more recesses,
6 coatings or non-uniform surfaces such as grooves,
7 ribs or the like. This has the advantage of
8 increasing the resistance to lateral movement
9 occurring between the liner and the tubular member
10 preventing the tubular member from being pushed down
11 or pulled out of the liner or borehole.

12

13 Additional seal means may be utilised to provide a
14 seal between the tubular member and the inside wall
15 of the liner. The additional seal means may be
16 provided by the (typically metal to metal)
17 engagement between the inner surface of the liner
18 and the outer surface of the tubular member to
19 provide a hydraulic and/or gas seal therebetween.
20 Alternatively, or in addition, further additional
21 seal means may be provided, typically on the outer
22 surface of the tubular member, to provide a
23 hydraulic and/or gas seal between the tubular member
24 and the liner. The further additional seal means
25 may be formed from an elastomeric material and may
26 be provided in the form of a band or a ring.

27

28 According to a second aspect of the present
29 invention, there is provided a method of securing a
30 first tubular member to a second tubular member
31 already located within a liner or borehole of a
32 well, the method comprising:-

1 inserting the first tubular member into the
2 borehole such that a lower end thereof is in close
3 proximity with an upper end of the second tubular
4 member; and

5 increasing the pressure within one of the first
6 and second tubular members between a pair of seal
7 means associated with one of the first and second
8 tubular members, such that the pressure increase
9 causes one of the first and second tubular members
10 to move radially to bear against a surface of the
11 other of the first and second tubular members,
12 wherein at least one of the first and second tubular
13 members undergo elastic deformation and also plastic
14 deformation.

15

16 According to the second aspect of the present
17 invention, there is also provided an apparatus for
18 securing a first tubular member to a second tubular
19 member already located within a liner of borehole of
20 a well, the apparatus comprising:-

21 a pair of seal means associated with one of the
22 first and second tubular members;

23 and a pressure control means operable to
24 increase the pressure within one of the first and
25 second tubular members between the pair of seal
26 means;

27 such that operation of the pressure control
28 means causes one of the first and second tubular
29 members to move radially to bear against a surface
30 of the other of the first and second tubular
31 members;

1 such that at least one of the first and second
2 tubular members undergo elastic deformation and also
3 plastic deformation.

4

5 Preferably, the pressure control means is also
6 operable to monitor the pressure within the tubular
7 member. Typically, the pressure control means is
8 also operable to control the pressure within said
9 one of the first and second tubular members.

10

11 Typically, the pair of seal means are associated
12 second tubular member, and preferably the pair of
13 seal means are mounted on a body member.

14 Preferably, the body member is lowered into the
15 wellbore, typically through the first tubular
16 member, by an elongate member such as a string of
17 drill pipe, coiled tubing or wireline and is further
18 lowered into the second tubular member. Preferably,
19 the body member is lowered to the proximate to the
20 upper end of the second tubular member until the
21 body member is generally aligned with one or more
22 profiles formed on a surface of the first tubular
23 member. Typically, the profiles are formed on an
24 internal surface of the first tubular member.

25 Preferably, an overshoot device is provided at or
26 toward the lower end of the first tubular member and
27 the one or more profiles are formed on an inner bore
28 of the overshoot device. Preferably, the pair of
29 seal means are longitudinally spaced apart on the
30 body member and the pair of seal means are typically
31 arranged such that they are spaced further apart
32 than the longitudinal extent of the one or more

1 profiles. Typically, the body member is lowered
2 into the first body member until the pair of seal
3 means straddle the one or more profiles.
4
5 Preferably, the pair of seal means are actuated to
6 seal against the inner bore of the second tubular
7 member. Preferably, the body member is provided
8 with one or more fluid ports or apertures typically
9 in its sidewall. Preferably, a fluid, which may be
10 a hydraulic fluid, is used to provide the pressure
11 and typically the fluid is pumped through the first
12 tubular member or if possible the elongate member,
13 through the one or more fluid ports and into a
14 chamber defined between the outer surface of the
15 body member, the inner bore of the first tubular
16 member and the pair of seal means. Typically, once
17 the pressure has increased to a sufficient level,
18 one or more portions, which are preferably
19 circumferential portions, of the first tubular
20 member are expanded or swaged into a respective
21 number of the one or more profiles of the overshoot
22 device to form a joint between the first tubular
23 member and the overshoot device of the second tubular
24 member. Accordingly, the one or more portions of
25 the second tubular member are preferably moved
26 radially outwardly such that the one or more
27 portions undergo elastic deformation and also
28 plastic deformation. The first tubular member is
29 preferably formed from a suitable metal material,
30 such as steel or an alloy material.
31

1 Preferably, the pair of seal means comprise a pair
2 of sealing devices in accordance with the third
3 aspect of the present invention.

4

5 Typically, the method according to the second aspect
6 of the present invention further comprises pulling
7 the elongate member and the body member out of the
8 well.

9

10 Preferably, the seal means are in the form of packer
11 elements or segments, and which may be provided with
12 support means.

13

14 Typically, the pressure, flow volume, depth and
15 diameter of the tubular at any given time will be
16 monitored and recorded by either downhole
17 instrumentation or surface instrumentation.

18

19 According to a third aspect of the present invention
20 there is provided a sealing device for use in an
21 annular space, where the sealing device comprises:-

22 at least one substantially cylindrical inner
23 element;

24 at least one seal assembly; and

25 a displacement means operable to apply a force
26 on the said seal assembly;

27 where the said inner element comprises a wedge
28 member, and the said seal assembly is slidable over
29 the wedge member along the longitudinal direction of
30 the inner element, wherein the said seal assembly
31 expands radially outward when forced over the wedge
32 member;

1 the seal assembly comprising a radially
2 expandable annular seal supported by at least one
3 radially expandable support sleeve;

4 characterised in that the support sleeve forms
5 a substantially continuous support surface towards
6 the said annular seal in both expanded and non-
7 expanded positions.

8
9 Preferably, the support sleeve comprises fingers
10 supporting the said annular seal and more preferably
11 the support sleeve comprises at least two types of
12 fingers. Typically, the sealing device comprises
13 two radially expandable support sleeves.

14
15 Preferably, the sealing device is a packer device
16 for use in a production tube, casing tube, liner
17 tube or the like. Typically, the displacement means
18 is disposed between the said inner element and the
19 said seal assembly. Preferably, the fingers are
20 connected to an end of their respective support
21 sleeve.

22
23 Typically, the first type of finger comprises a
24 generally triangular support member, the end surface
25 of which defines a support surface and the second
26 type of finger preferably comprises a generally
27 triangular support member being generally T-shaped
28 seen from above, the end of which defines a support
29 surface, where the other side of the support member
30 defines a support surface. More preferably, every
31 second finger of the support sleeve is of the first

1 type of finger, or the second type of finger
2 respectively.

3

4 Preferably, the support surfaces of the second type
5 of fingers in a running in hole position rest on the
6 support surfaces of the first type of fingers.

7 Typically, the support surfaces of the second type
8 of fingers in a running in hole position are resting
9 on at least some of the support surfaces of the
10 first type of fingers.

11

12 Typically there are at least two packer devices
13 connected by means of a mandrel. Preferably, an
14 annular sleeve is disposed between the at least two
15 packer devices and the production tube, said annular
16 sleeve being disposed in a longitudinal direction
17 between two seal assemblies, wherein the annular
18 sleeve preferably provides a sealing surface towards
19 the production tube.

20

21 Alternatively, an isolation plug is provided which
22 comprises one packer device which could be run on
23 drill pipe, coil tubing or wireline. Setting of the
24 plug may be by hydraulic or mechanical means.

25 Typically, a seal setting piston is attached to a
26 mandrel which protrudes through an upper end of the
27 single packer device of the plug. Preferably, the
28 mandrel is attached to a setting tool, such that
29 when the mandrel is pulled upwards against a sleeve
30 mounted against the upper end of the single packer
31 device or isolation plug, the annular seal is
32 activated and is extruded outwardly to contact the

1 casing wall or downhole tubular, for instance.
2 Final setting loads of the plug may be set via
3 either a mechanical shear means when set
4 mechanically or via the final hydraulic pressure
5 when set with hydraulic means. The seal setting
6 piston would be maintained in the set position via
7 locking the hydraulics in place for a hydraulic set
8 or with slips or a ratchet mechanism for mechanical
9 sets.
10
11 For retrieval of the plug, the annular seal would be
12 de-activated via releasing the hydraulic pressure or
13 by releasing the ratchet/slip mechanism.
14
15 For high differential pressures, the setting force
16 would be sufficiently high to swage the casing or
17 downhole tubular with the single seal assembly or
18 isolation plug, thereby key seating the seal
19 assembly into the well delivering a large resistance
20 to movement up or down the well.
21
22 According to a fourth aspect of the present
23 invention there is provided an isolation plug for
24 plugging a downhole tubular, the isolation plug
25 comprising a sealing device according to the third
26 aspect of the present invention and a seal actuation
27 mechanism, the seal actuation mechanism being
28 operable to expand the annular seal radially
29 outwards toward the downhole tubular to firstly seal
30 against an inner bore thereof and secondly
31 elastically and furthermore plastically deform the
32 downhole tubular.

1
2 According to a fifth aspect of the present invention
3 there is provided a method of plugging a downhole
4 tubular comprising inserting an isolation plug into
5 the downhole tubular to a desired location and
6 expanding a seal means of the isolation plug in a
7 radially outwards direction toward the downhole
8 tubular by operating a seal actuation mechanism of
9 the isolation plug such that the seal means firstly
10 seals against an inner bore of the downhole tubular
11 and secondly elastically and furthermore plastically
12 deforms the downhole tubular.

13
14 The seal actuation mechanism may comprise a
15 hydraulic or mechanical means but preferably
16 comprises a hydraulic means. The isolation plug may
17 be run into the downhole tubular on drill pipe, coil
18 tubing or wireline.

19
20 According to a sixth aspect of the present invention
21 there is provided a method of providing a downhole
22 metal to metal seal between two concentrically
23 arranged tubulars, comprising the steps of:-

24
25 a) expanding radially outwardly the innermost
26 tubular through elastic and then plastic deformation
27 until it contacts the inner bore of the second
28 tubular; and

29
30 b) continued expansion of the first tubular such
31 that it firstly elastically and secondly plastically
32 expands the second tubular radially outwardly.

1
2 Embodiments of the six aspects of the present
3 invention will now be described, by way of example
4 only, with reference to the accompanying drawings,
5 in which:-

6
7 Fig. 1 is a schematic representation of an
8 apparatus, in accordance with a first aspect of
9 the present invention, being conveyed through a
10 liner on wireline, drill pipe or coiled tubing
11 toward a location at which it will be operated;
12 Fig. 2 is a schematic representation of the
13 apparatus of Fig. 1 adjacent to the location in
14 the liner at which it will be operated;
15 Fig. 3 is a schematic representation of the
16 apparatus of Fig. 1 during its operation;
17 Fig. 4 is a graph of pumped volume on the X-
18 axis versus setting pressure on the Y-axis
19 indicating the expansion of a tubular member
20 shown in Fig. 3;
21 Fig. 5 is a schematic representation of the
22 apparatus of Fig. 1 during continued operation;
23 Fig. 6 is a table of pumped volume versus
24 setting pressure indicating the expansion of
25 the tubular member shown in Fig. 5, the tubular
26 member now having passed the elastic limit and
27 going through permanent plastic deformation;
28 Fig. 7 is a schematic representation of the
29 apparatus of Fig. 1 after continued operation,
30 with the tubular member making contact with the
31 liner wall;

1 Fig. 8 is a table of pumped volume versus
2 setting pressure for the representation shown
3 in Fig. 7;
4 Fig. 9 is a schematic representation of the
5 apparatus of Fig. 1 after continued operation;
6 Fig. 10 is a graph of the pumped volume versus
7 setting pressure for the representation shown
8 in Fig. 9;
9 Fig. 11 is a schematic representation of the
10 apparatus of Fig. 1 following continued
11 operation;
12 Fig. 12 is a second embodiment of an apparatus
13 in accordance with the first aspect of the
14 present invention, showing a variable length
15 extrudable liner/casing patch;
16 Fig. 13 is a third embodiment of an apparatus
17 in accordance with the first aspect of the
18 present invention, incorporating a tubing
19 receptacle and seal assembly (also known as a
20 seal assy) and due to the heavy loading applied
21 to the seal assy, the liner is shown with a
22 recess profile into which the tubular member
23 will be plastically deformed;
24 Fig. 14a is a schematic representation of the
25 seal assy of Fig. 13, after the apparatus has
26 been operated, showing the plastic deformation
27 of the tubular member into the recess in the
28 liner wall;
29 Fig. 14b is a detailed schematic representation
30 of a portion of the representation of Fig. 14a
31 showing the plastic deformation of the tubular
32 member into the recess in the liner wall;

1 Fig. 15a is a schematic representation of a
2 fourth embodiment of an apparatus in accordance
3 with the first aspect of the present invention,
4 incorporating a nipple profile to be set in a
5 liner;
6 Fig. 15b is a detailed schematic representation
7 of a portion of the apparatus of Fig. 15a again
8 showing the plastic deformation of the tubular
9 member into the recess in the liner wall which
10 will withstand severe lateral loading;
11 Fig. 16a is a schematic representation of a
12 fifth embodiment of an apparatus in accordance
13 with the first aspect of the present invention,
14 incorporating a tubular member with an
15 extension of a temporary liner to be set across
16 a washed-out section of a borehole below a
17 casing shoe;
18 Fig. 16b is a detailed schematic representation
19 of a portion of the representation of Fig. 16a
20 again showing the plastic deformation of the
21 tubular member into the recess in the liner
22 wall;
23 Fig. 17 is a first example of a method of
24 conveyance for an apparatus in accordance with
25 the first aspect of the present invention,
26 utilising wireline and possibly containing
27 downhole telemetry for control of the pressure
28 and flow sensors and logic control of the
29 hydraulics, and this equipment may also contain
30 a fluid reservoir which feeds the pump and
31 generates the pressure;

1 Fig. 18 is a second example of a method of
2 conveyance for an apparatus in accordance with
3 the first aspect of the present invention,
4 utilising drill pipe or coil tubing, and in
5 this example, the pressure and flow may be
6 applied and monitored from surface of the
7 borehole;
8 Fig. 19 is a schematic representation of a
9 sixth embodiment of an apparatus in accordance
10 with the first aspect of the present invention,
11 incorporating a liner section constructed from
12 a malleable material which is capable of a high
13 degree of plastic expansion;
14 Fig. 20 is a schematic representation of the
15 embodiment of Fig. 19, wherein the liner has
16 been expanded and forms a barrier, akin to a
17 mud cake, within an open hole section of the
18 borehole, and which is possibly pinned in
19 place;
20 Fig. 21 is a schematic representation of a
21 first embodiment of a tubular member such as a
22 casing or liner string which has been cut
23 downhole and which will have a "tie back"
24 operation performed on it in accordance with a
25 second aspect of the present invention;
26 Fig. 22 is a schematic representation of a
27 swage overshot apparatus in accordance with the
28 second aspect of the present invention being
29 lowered over the upper end of the tubular
30 member of Fig. 21;
31 Fig. 23 is a schematic representation of a
32 packer in accordance with the second aspect of

1 the present invention being lowered into
2 position within the swage overshot apparatus of
3 Fig. 22;
4 Fig. 24 is a more detailed schematic
5 representation of the packer of Fig. 23 being
6 actuated within the swage overshot apparatus;
7 Fig. 25 is schematic representation of the
8 packer of Fig. 24 after actuation and after the
9 tubular member has been swaged into formations
10 provided within the swage overshot apparatus;
11 Fig. 26 is a schematic representation of the
12 tubular member of Fig. 25 after the packer has
13 been removed therefrom;
14 Fig. 27 is a more detailed longitudinal cross-
15 sectional view of the packer of Fig. 23 prior
16 to actuation in the running in hole
17 configuration and within a tubular member;
18 Fig. 28 is a further longitudinal cross-
19 sectional view of the packer of Fig. 27 prior
20 to actuation in the running in hole
21 configuration;
22 Fig. 29 is a longitudinal cross-sectional view
23 of a very similar packer to the packer of Fig.
24 28 after actuation in a setting configuration;
25 Fig. 30 is a part longitudinal cross-sectional
26 view of the seal assembly and the inner element
27 of the packer of Fig. 29 in running position;
28 Fig. 31 is a part longitudinal cross-sectional
29 view of the seal assembly and the inner element
30 of the packer of Fig. 29 in setting position;

1 Fig. 32 is a perspective view of the support
2 ring for the seal assembly of the packer of
3 Fig. 29; and
4 Fig. 33 shows fingers of the support ring in
5 detail, where

6 Fig. 33a shows a first finger type seen
7 from the side;

8 Fig. 33b shows a second finger type from
9 the side; and

10 Fig. 33c shows the second finger type of
11 Fig. 33b from above.

12

13 Fig. 1 shows an apparatus in accordance with the
14 present invention, and which can be used to provide
15 a method in accordance with the first and sixth
16 aspects of the present invention. The apparatus is
17 generally designated at 1.

18

19 The apparatus 1 comprises a body 5 which is run into
20 a casing, liner or tubing 7 or a borehole (not
21 shown) by means of wireline (not shown in Fig. 1 but
22 see Fig. 17), coiled tubing (not shown) or drill
23 pipe (not shown in Fig. 1 but see Fig. 18), or some
24 other suitable conveyance means, and which is
25 attached to the body 5 at the upper end 5t thereof.
26 The body 5 is generally tubular in shape, and
27 preferably comprises hydraulic logic to control the
28 setting sequence.

29

30 A liner patch 9 or tubular member 9 (hereinafter
31 referred to as tubular member 9) is shown in Fig. 1.
32 The tubular member 9 is a cylinder, and is arranged

1 co-axially about the body 5. The tubular member 9 is
2 secured, at its upper 9U and lower 9L ends, to the
3 body 5 by any suitable means, such as hydraulically
4 actuated centralising pins 11. The apparatus 1 also
5 comprises a pair of seal members 13, which are in
6 the form of packer elements 13, and which are
7 typically arranged axially inwards of the pins 11
8 and steel back up segments that prevent extrusion of
9 the seal packer elements 13. Preferably, the seal
10 packer elements 13 are those 116 or 214, 215
11 described subsequently in relation to Figs. 27 to
12 31. In this manner, the apparatus 1 comprises a
13 chamber 15 which is defined in volume by the inner
14 surfaces of the packer elements 13, the inner
15 circumference of the tubular member 9, and the outer
16 surface of the body 5. The chamber 15, as shown in
17 Fig. 1, is sealed by the packer elements 13 with
18 respect to the environment outside of the chamber
19 15.

20

21 A port 17 is formed in the side wall of the body 5,
22 such that the inner bore of the body 5 is in fluid
23 communication with the chamber 15. The body 5 also
24 constrains the opposing hydraulic forces between the
25 seals 13 when pressure is applied in the chamber 15.

26

27 In one embodiment of the invention, the apparatus 1
28 can be run into a liner or borehole on coiled tubing
29 or drill pipe and in this case, the port 17 is in
30 fluid communication with the interior of the coiled
31 tubing or drill pipe respectively.

32

1 However, in another embodiment of the invention, the
2 apparatus 1 can be run into the liner or borehole on
3 wireline, and in this embodiment, the port 17 is in
4 fluid communication with a motor pump and fluid
5 reservoir tool which is also run into the liner or
6 borehole with the apparatus, details of which will
7 be described subsequently.

8
9 Alternatively, in a yet further embodiment, only one
10 upper seal assembly 13 may be provided if the lower
11 end of the liner patch/tubular member 9 were closed
12 or somehow else sealed.

13
14 A method in accordance with the present invention
15 will now be described.

16
17 The apparatus 1 is conveyed into the liner or
18 borehole by any suitable means, such as wireline,
19 coiled tubing or drill pipe until it reaches the
20 location within the liner or borehole at which
21 operation of the apparatus is intended. This
22 location is shown in Fig. 2 as being a location
23 within the liner 7 or borehole at which there is
24 either damage to the liner 7, shown at 19, or where
25 apertures 19 in the liner 7 require to be obturated.
26 At this point, isolation seals are actuated from
27 surface (in the situation where drill pipe or coiled
28 tubing is being used) to allow hydraulic fluid to be
29 pumped under pressure down the bore of the coiled
30 tubing or drill pipe, such that the hydraulic fluid
31 flows through the port 17 into the chamber 15. In
32 the case where wireline is being used to convey the

1 apparatus 1 into the borehole, the pump motor is
2 operated to pump hydraulic fluid from the fluid
3 reservoir into the chamber 15 through the port 17.
4 This causes the packer elements 13 to move outwardly
5 to seal against the inner circumference of the ends
6 9U, 9L of the tubular member 9. Hence, a high
7 pressure seal is formed between the packer elements
8 13 and the tubular member 9. The pressure between
9 the packer element seals 13, and hence within the
10 chamber 15, continues to increase, such that the
11 tubular member 9 initially experiences elastic
12 expansion, and then plastic expansion, in an
13 outwards direction which is shown in Fig. 3 and in
14 the graph of Fig. 4. The tubular member 9 expands
15 beyond its yield point, undergoing plastic
16 deformation and this is shown in the graph of Fig.
17 6, until the tubular member 9 forces against the
18 inner surface of the liner 7, as shown in Fig. 5.
19 The packer elements 13, and associated steel back-up
20 rings (not shown) also continue to move outwardly,
21 such that the chamber 15 is sealed. If desired, the
22 pressure of fluid within the chamber 15 can be bled
23 off at this point.

24
25 Alternatively, the increase of pressure within
26 chamber 15 can be maintained, such that the tubular
27 member 9 continues to move outwardly against the
28 liner 7, such that the liner 7 starts to experience
29 elastic expansion, and this situation is shown in
30 Fig. 7 and in the graph of Fig. 8. As will be
31 understood, as the tubular member 9 makes contact
32 with the liner wall 7, the pressure increases due to

1 the resistance of the liner wall 7 until the liner
2 wall 7 undergoes elastic deformation, typically in
3 the region of up to half a percent. The pressure
4 can be increased up to the desired level, which may
5 be many thousand psi. The increase in the pump
6 volume and setting pressure of fluid can be
7 continued until a desired level of plastic expansion
8 of the tubular member 9 has occurred, and with the
9 liner 7 having only undergone elastic expansion,
10 when the pressure of the fluid is reduced, the liner
11 7 will maintain a compressive force inwardly upon
12 the plastically expanded tubular member 9, and this
13 situation is shown in Fig. 7 and in the graph shown
14 in Fig. 8. Hence, with the liner 7 having undergone
15 elastic deformation, the pressure is released on the
16 seals (in the form of the packer elements 13, and
17 associated steel back-up rings) and the locating
18 pins 11 will automatically withdraw. The tubular
19 member 9 is securely held since it has undergone
20 plastic deformation and the liner 7 remaining in
21 elastic deformation. The liner 7 undergoes plastic
22 deformation to typically 80% of it's yield
23 (approximately up to 0.4% elastic expansion).

24
25 Optionally, the liner wall 7 could be yielded to 1%
26 plastic expansion and this is shown in Figs. 9 and
27 10.

28
29 Hydraulic logic and associated valves and switching
30 arrangements are provided within the pressure system
31 located within the body 5, and the logic is arranged

1 such that when the pressure is released, the pins 11
2 are released.

3
4 The releasing of the pressure of the fluid causes
5 the hydraulically actuated centralising pins 11 to
6 retract radially inward into the body 5, and this
7 also causes the packer elements 13 to retract
8 radially inward toward the body 5, such that the
9 seal between the body 5 and tubular member 9 is
10 released, and the body 5 is free from engagement
11 with the tubular member 9. The body 5 can then be
12 withdrawn upwards from the borehole, and as shown in
13 Fig. 11, the tubular member is held in compression
14 by the force of the elastic compression of the
15 tubing 7 across the full length and circumference of
16 the tubular member 9.

17
18 The arrangement of double packer elements 13 is most
19 suitable for relatively short length of tubular
20 members 9 in the region of up to a few meters in
21 length. This relatively short length tubular member
22 9 is suitable for use in water shut-off across
23 perforations or tubing leaks, and repairing damaged
24 casing or liner tubing 7.

25
26 In order to reduce the hoop strain experienced by
27 the very ends of the tubular member 9 or liner patch
28 9, and in order to ensure that the full length of
29 the liner patch 9 is fully expanded, it is
30 preferable to cut longitudinally arranged slots (not
31 shown) spaced apart about the circumference of the
32 very end of the liner patch 9.

1
2 An alternative embodiment of the invention is shown
3 in Fig. 12 and provides a variable length extrudable
4 tubular member 9. As shown in Fig. 12, the tubular
5 member 9 is of any suitable length. The embodiment
6 of Fig. 12 comprises an upper body section 21, and a
7 lower body section 23, both of which comprise
8 hydraulically actuated centraliser pins 11 and
9 sealing members 13 in the form of packer elements
10 13, as with the first embodiment of the apparatus 1.
11 The port 17 is carried on the upper body section 21,
12 and the second embodiment is operated in a similar
13 manner to the first embodiment 1. However, slips 50
14 are provided on the upper body section 21, and act
15 between the upper body section 21 and the inner
16 surface of the upper end of the extrudable tubular
17 member 9 in order to ensure that there is no
18 unwanted slippage therebetween when the pressure
19 within the chamber 15 increases. Internal dogs,
20 inwardly projecting keys, or another suitable
21 arrangement (generally designated at 52) are
22 provided on the inner surface of the lower in use
23 end of the tubular member 9 and which act to stop
24 the lower body section 23 from bursting out of the
25 lower end of the lower body section 23 when the
26 pressure within the chamber 15 increases. The lower
27 body section 23 can be retrieved from the interior
28 of the tubular member 9 after the tubular member 9
29 has been expanded, for instance by a fishing
30 operation, or the lower body section 23 can be
31 pumped out of the lower end of the tubular member 9.
32

1 A third embodiment of an apparatus in accordance
2 with the present invention is shown in Fig. 13 as
3 comprising a body 5 with upper and lower packer
4 elements 13 and upper and lower sets of
5 hydraulically actuated centralising pins 11. The
6 body also carries a port 17 located between the two
7 packer elements 13 and is operated in a similar
8 manner to the apparatus 1. However, the tubular
9 member 9 is integrally formed with a seal assy 25 at
10 its lower end, which can be used as a tubing
11 receptacle and seal assembly. It should be noted in
12 Fig. 13 that the liner 7 has been pre-formed with a
13 bank of recesses 27 which are axially spaced along a
14 short length of the interior surface of the liner 7.
15 In the examples shown in Fig. 13, there are four
16 recesses 27, but any suitable number of recesses 27
17 can be provided. Alternatively, no recesses need be
18 provided and in this scenario the tubular member 9
19 is expanded until the liner 7 or casing 7
20 plastically expands in order to ensure a high
21 quality metal to metal seal is created.

22

23 Where recesses are provided, as seen most clearly in
24 Fig. 14b, the tubular member 9 will expand into the
25 recesses 27, and the engagement there between will
26 provide the tubular member 9 with a much higher
27 resistance to lateral movement through the liner.
28 In the example given in Fig. 14a, the tubular member
29 9 is used to set the tubing receptacle and seal
30 assembly (also known as a seal bore receptacle)
31 within the liner 7.

32

1 As shown in Figs. 15a and 15b, the lower end of the
2 tubular member 9 is secured to a nipple profile 29,
3 and hence can be used to set the nipple profile 29
4 within the liner 7.

5
6 A further alternative embodiment of the invention is
7 shown in Fig. 16a, and Fig. 16b, where the lower end
8 of the tubular member 9 is secured to a temporary
9 liner section 31. In this example, the temporary
10 liner section 31 is set across a washed-out section
11 below the casing shoe at the very end of the liner
12 7.

13
14 As previously described, the apparatus 1 can be
15 conveyed into the borehole by means of drill pipe 33
16 or coiled tubing with pressure controlled from the
17 surface, and in this example, the drill pipe 33 is
18 shown in Fig. 18.

19
20 Alternatively, the apparatus 1 can be conveyed into
21 the borehole by means of wireline 35, and in this
22 example, the apparatus 1 is coupled to the lower end
23 of a sensor tool 37 which can be used to indicate
24 the pressure of fluid being pumped into and through
25 the port 17. The upper end of the sensor tool 37 is
26 coupled to the lower end of a motor pump and
27 hydraulic fluid reservoir 39, the upper end of which
28 is coupled to the lower end of telemetry tool 41
29 which can be used to indicate the position of this
30 bottom hole assembly to the operator at the surface.

31

1 Fig. 19 shows a further embodiment of an apparatus
2 in accordance with the present invention. This
3 embodiment of the invention provides a variable, and
4 in this example, extended length liner in the form
5 of an extrudable tubular member 9. As shown in Fig.
6 19, the tubular member 9 is of any suitable length.
7 The embodiment of Fig. 19 comprises an upper body
8 section 21, and a lower body section 23, both of
9 which comprise hydraulically actuated centraliser
10 pins 11 and sealing members 13 in the form of packer
11 elements 13, as with the first embodiment of the
12 apparatus 1. The port 17 is carried on the upper
13 body section 21, and the embodiment of Fig. 19 is
14 operated in a similar manner to the first embodiment
15 1. However, slips 50 are provided on the upper body
16 section 21, and act between the upper body section
17 21 and the inner surface of the upper end of the
18 extrudable tubular member 9 in order to ensure that
19 there is no unwanted slippage therebetween when the
20 pressure within the chamber 15 increases. Internal
21 dogs, inwardly projecting keys, or another suitable
22 arrangement (generally designated at 52) are
23 provided on the inner surface of the lower in use
24 end of the tubular member 9 and which act to stop
25 the lower body section 23 from bursting out of the
26 lower end of the lower body section 23 when the
27 pressure within the chamber 15 increases. The lower
28 body section 23 can be retrieved from the interior
29 of the tubular member 9 after the tubular member 9
30 has been expanded, for instance by a fishing
31 operation, or the lower body section 23 can be
32 pumped out of the lower end of the tubular member 9.

1 The pressure within the chamber 15 is increased as
2 before, such that the tubular member 9 expands to
3 meet the inner surface of the open hole section of
4 the borehole, which may be a greater diameter than
5 the drill bit diameter, as shown in Fig. 20. Pins
6 55 may optionally be provided as shown in Figs. 19
7 and 20, through the side wall of the tubular member
8 9 (with a suitable sealing arrangement
9 therebetween), such that the pins are forced into
10 the formation to enhance the grip between the
11 formation and the tubular member 9. The pins 55 (if
12 present) are preferably run into the borehole, such
13 that they are projecting inwardly from the tubular
14 member, so that no obstruction is provided by the
15 pins 55, on the outer surface of the tubular member
16 9, when the apparatus is being run into the
17 borehole. The tubular member 9 of Figs. 19 and 20
18 is preferably formed from a relatively highly
19 malleable, and thus relatively highly extrudable,
20 metal, such that it can undergo a relatively large
21 degree of plastic deformation without rupturing.
22 Additionally during the setting sequence of the
23 tubular member 9, the hydrostatic pressure within
24 the borehole, which to a large extent is created by
25 the amount of fluids which have been introduced into
26 the borehole from surface, may be reduced (by
27 withdrawn a volume of these fluids from the
28 borehole) so that when the tubular member 9 is
29 expanded and the pressure taken off, there is a
30 pressure overbalance between the inside of the
31 borehole and the formation pressure. This pressure

1 overbalance will yet further assist holding the
2 tubular member 9 in place.

3
4 Therefore, it can be seen that the apparatus 1 can
5 be provided with an uninterrupted central mandrel
6 section which couples to both the upper and lower
7 ends of the tubular member 9, such as the one piece
8 body section 5 of the first embodiment shown in Fig.
9 1, or can be provided with split upper 21 and lower
10 23 body sections which are respectively coupled to
11 the upper and lower ends of the tubular member 9,
12 such as the embodiment shown in Fig. 12. In the
13 latter scenario, the opposing forces on the seals 13
14 are contained by, for instance slips (as indicated
15 for the top seal 13), or a no go (as indicated for
16 the bottom seal 13). Also, the length of the
17 tubular member 9 is variable, depending upon
18 conveyance technique, well geometry etc.

19
20 The expansion of the tubular member 9 against the
21 inner surface of the liner 7 may provide a high
22 integrity hydraulic fluid and/or gas seal
23 therebetween, and this will particularly be the case
24 when the tubular member 9 is expanded into recesses
25 27. However, the high integrity seal can be further
26 aided by the provision of one or more elastomeric
27 bands or rings around the outer circumference of the
28 tubular member 9.

29
30 A first embodiment of a swage casing tie-back system
31 100 is shown in Figs. 21 to 26 and is in accordance

1 with the second, third and sixth aspects of the
2 present invention.

3
4 Fig. 21 shows a borehole 102 having a diameter of 12
5 $\frac{1}{4}$ inches which has been previously lined with a
6 $9\frac{7}{8}$ inch diameter casing string 104. However, it
7 should be noted that the embodiments described below
8 can be used with differently sized boreholes 102
9 and/or casing strings 104. Normally, as those
10 skilled in the art will realise, the casing string
11 104 extends all the way up to the surface. However,
12 in this case, the upper portion of the casing string
13 (not shown) has been cut away from the lower portion
14 of the casing string 104 and has been removed from
15 the borehole 102. In some circumstances, casing
16 strings can be backed off but in circumstances where
17 the casing string failed to back-off, the swage
18 casing tie-back system 100 would be utilised.

19
20 Fig. 22 shows that a tie-back casing string 106 has
21 been run into the borehole 102, the casing string
22 106 having a swage overshot device 108 mounted at
23 its lower end. The swage overshot device 108 is
24 formed from a relatively tough material such as P110
25 grade steel and comprises a number (such as three as
26 shown in Fig. 22) of internal recesses 110 or
27 profiles formed on its inner bore. The rest of the
28 internal bore of the overshot device 108 has a
29 diameter just slightly larger than the outer
30 diameter of the casing string 104 such that the
31 overshot device 108 slips over the upper end of the
32 casing string 104 like a sleeve.

1
2 Fig. 23 shows the next sequence of events where a
3 body member comprising a packer tool 112 is run on
4 the lower end of a string of drillpipe 114, down
5 through the upper casing string 106 until the packer
6 tool 112 is aligned with the annular recesses 110 of
7 the overshoot device 108. The packer tool 112
8 comprises a pair of seal elements 116 which are
9 preferably longitudinally spaced apart by a distance
10 which is slightly greater than the longitudinal
11 distance between the uppermost annular recess 110
12 and the lowermost annular recess 110. An
13 arrangement of apertures 118 which extend all the
14 way through the side wall of the overshoot device 108
15 are provided between the longitudinally spaced apart
16 pair of seal elements 116.

17
18 Fig. 24 shows that the seal elements 116 have been
19 actuated to form a seal between the outer surface of
20 the packer tool 112 and the inner surface of the
21 casing string 104 such that the annular region or
22 chamber between the pair of seal elements 116 is
23 sealed with respect to the annular region outside of
24 the pair of seal elements 116. Fig. 24 also shows
25 that water is pumped through the throughbore of the
26 drillstring 114, into the interconnecting bore of
27 the packer tool 112 and through the apertures 118
28 and into the annular region or chamber between the
29 pair of seal elements 116. The water is continued
30 to be pumped into the aforesaid chamber until the
31 pressure reaches the desired level such as up to or
32 perhaps even greater than 30,000psi. As this

1 hydraulic pressure increases, the force provided by
2 it moves or swages the casing string 104 into the
3 annular recesses 110 as shown in Fig. 25.
4 Accordingly, the casing string 104 is now tied back
5 to the casing string 106.

6
7 The pair of sealing elements 116 are then de-
8 activated and the drillpipe string 114 and thus the
9 packer tool 112 are removed from the casing strings
10 104, 106.

11
12 Thus, as shown in Fig. 26, the casing 104 is
13 permanently expanded into the internal profile or
14 recesses 110 of the overshot device 108 by firstly
15 elastic deformation and secondly plastic deformation
16 thus achieving a mechanical and pressure tight
17 joint. Indeed, after the retrieval of the drillpipe
18 114 and the packer tool 112, the resulting joint has
19 comparable mechanical integrity to the original
20 casing string 104 and makes no reduction in internal
21 diameter. Furthermore, the resulting joint provided
22 is a metal to metal seal.

23
24 It should also be noted that the casing strings 104,
25 106 could be a string of liner tubings or production
26 tubings or the like.

27
28 Fig. 27 shows a first embodiment of a packer tool
29 112 in accordance with both the second and the third
30 aspects of the present invention, although the lower
31 end of the drillpipe string 114 is omitted for
32 clarity purposes. It should be noted that the

1 packer tool 112 is broadly the same as the packer
2 tool 210 of Figs. 28 and 29, although the skilled
3 reader will realise that the pair of wedge members
4 122 of the packer 112 are arranged in the opposite
5 direction to the pair of wedge members 222 of the
6 packer 210. However, this does not effect the
7 operation of the packer tool 112 compared with the
8 packer 210. Accordingly, only the packer 210 will
9 be described in detail.

10

11 Fig. 28 shows a packer tool 210 in accordance with
12 the second, third, fifth and sixth aspects of the
13 present invention disposed in an annular space, such
14 as a production tube 211, and can be modified to
15 provide the spaced apart seals of the embodiments
16 of the first aspect of the invention. The packer
17 210 comprises a first, upper, inner element 212
18 which acts as a piston, a second, lower, inner
19 element 213 which also acts as a piston, a first
20 seal assembly 214 and a second seal assembly 215,
21 which will be described in detail further below.
22 The two inner elements 212, 213 are telescopically
23 coupled together by means of a mandrel 217. An
24 annular sleeve 218 is disposed between the packer
25 210 and the production tube 211 in the longitudinal
26 direction between the two seal assemblies 214 and
27 215. The annular sleeve 218 provides the sealing
28 surface towards the production tube 211.

29

30 The inner, upper, element 212 will now be described
31 with reference to Fig. 30. The inner element 212 is
32 generally cylindrical and comprises moveable

1 connection means in both ends for telescopic
2 coupling to the mandrel 217 and other equipment,
3 such as pipes, controlling means etc. respectively.
4 In addition, the inner element 212 comprises a wedge
5 member 222.

6
7 The seal assembly 214 (see Fig. 28) is slidable
8 disposed on the outside of the inner element 212,
9 and comprises an upper support sleeve 220, a lower
10 support sleeve 221 and a seal 223. The seal 223
11 comprise an annular expandable ring, preferably made
12 of expandable and temperature resistant materials.

13
14 Between the seal assembly 214 and the inner element
15 212 there are disposed displacement means 219 (shown
16 in Figs. 30 and 31. The displacement means 219
17 operates the sliding of the seal assembly 214
18 relative to the inner element 212. In this
19 embodiment the displacement means is a hydraulic
20 drive, and Figs. 30 and 31 show upper hydraulic
21 fluid chambers 219au and lower hydraulic fluid
22 chambers 219al which are selectively pressurised
23 with respective hydraulic fluid delivered from
24 surface via hydraulic lines (not shown). For
25 instance, in order to actuate the seal assembly,
26 pressurised fluid is forced into chamber 219al which
27 forces the inner element 212 downwards from the
28 position shown in Fig. 30 to the position shown in
29 Fig. 31 thus forcing the seal 223 to expand outwards
30 due to the wedge member 222 action upon it.

31

1 The support sleeves 220, 221 form the expandable
2 parts of the seal assembly together with the seal
3 223. The support sleeves 220, 221 preferably
4 comprise fingers of two different types, where every
5 second finger is of the same type. The fingers are
6 all connected to an end 230 of the support sleeve.
7 This is shown in detail in Fig. 32.

8
9 The first finger type 231 comprises an elongated
10 member 232. In the end opposite to the end 230 of
11 the support sleeve 220, the first finger 231
12 comprises a generally triangular support member 233,
13 the end surface of which defines a support surface
14 234.

15
16 The second finger type 241 comprises an elongated
17 member 42. In the end opposite to the end 230 of
18 the support sleeve 220, the second finger 241
19 comprises a generally triangular support member 243.
20 The support member 243 is differing from the support
21 member 233 in that it is generally T-shaped seen
22 from above (Fig. 33c). The end of the support
23 member 243 defines a support surface 244, and the
24 other side of the support member 433 defines a
25 support surface 245. Preferably, the crossbars of
26 the T-shaped support members 243 of the different
27 second type fingers 241 are lying next to each other
28 in the running in hole position.

29
30 The operation of the packer will now be described
31 with reference to Figs. 30 and 31.

32

1 Fig. 30 shows the upper part of the packer 210 in
2 the running in hole position. Here, the annular
3 seal 223 particularly rests on the support surfaces
4 244 of the second type fingers 241. The support
5 surfaces 245 of the second type fingers 241 are
6 further resting on the support surface 234 of the
7 first type finger 231. The annular seal 223 is in
8 the radially inward direction resting on the wedge
9 member 222 and in the radially outward direction
10 resting on the annular sleeve 218 (Fig. 28).

11
12 When the desired position of the packer 210 in the
13 production tube 211 is found, a compression force is
14 applied to the packer 210 by means of the
15 displacement means 219. The compressive force
16 results in a downwardly directed displacement of the
17 support sleeve 220 and compression of the support
18 sleeve 221 in Fig. 30. Consequently, the support
19 sleeve 221 together with the annular seal 223 climbs
20 the wedge member 222, which again causes the annular
21 seal 223 and the fingers 231, 241 of the support
22 sleeves 220, 221 to expand radially.

23
24 The expansion of the support sleeves 220, 221 is
25 shown in Fig. 31. The annular seal 223 is now
26 expanded to a larger radius, but has substantially
27 the same shape as the previous form. This is due to
28 the support sleeves 220, 221. Since the fingers of
29 the support sleeves 220, 221 have their mutual
30 distance increased, the crossbars of the T-shaped
31 support members 243 of the different second type
32 fingers 241 have their mutual distance increased.

1 The annular seal 223 is now resting on both the
2 support surfaces 234 of the first type finger 231
3 and the support surface 244 of the second type
4 finger 244. Preferably, the support surfaces 245
5 are also still resting on the support surfaces 234,
6 even though the contact surface between them has
7 decreased.

8
9 Consequently, the annular seal 223 is still
10 supported in the desired position in a way that
11 prevents extrusions of the seal 223, even under high
12 pressure.

13
14 Accordingly, the expansion of the seal assemblies
15 214, 215 causes the sleeve 218 to be pressed out
16 towards the casing or production tube with a large
17 force, and the seal 223 is now in the setting
18 position.

19
20 The operation from the setting position to the
21 running position is achieved by reducing the
22 compression force on the displacement means 219, by
23 means of relieving the pressure in chambers 219al
24 and increasing the pressure in chambers 219au which
25 causes the inner element 212 to move upwardly again
26 to the position shown in Fig. 30. As the annular
27 seal 223 slides down the wedge member 222 the radius
28 of the seal 223 will decrease and consequently the
29 fingers 231, 241 of the sleeves 220, 221 will go
30 back to their original position.

31

1 In Figs. 33a and 33c the support surfaces 234 and
2 244 are shown generally perpendicular to their
3 respective elongated members 232 and 242. These
4 support surfaces may of course have an angle with
5 their elongated members.

6
7 It should be noted that the production tube 211
8 could be a casing string or liner string or the
9 like.

10
11 All of the embodiments described herein have the
12 great advantage that they create a metal to metal
13 seal downhole.

14
15 Modifications and improvements may be made to the
16 embodiments without departing from the scope of the
17 invention. For instance, the packer tool 112 and/or
18 the packer tool 210 of Figs 27 and 28 respectively
19 could be modified to provide a plug (not shown) in
20 accordance with a fourth aspect of the present
21 invention and in this case, embodiments thereof
22 could comprise a single seal assembly 116 and
23 214/215 respectively, where the plug could be run on
24 drill pipe, coil tubing or wireline. Setting of the
25 plug would be via hydraulic or mechanical means. A
26 seal setting piston (not shown) would be attached to
27 a mandrel (not shown) that protrudes through the top
28 of the single seal assembly of the plug. This
29 mandrel would be attached to a setting tool, such
30 that when the mandrel is pulled upwards against a
31 sleeve (not shown) acting on the top of the seal

1 assembly, the seal is activated and is extruded
2 outwardly to contact the casing wall, for instance.
3
4 Final setting loads of the plug would vary,
5 depending on the differential pressure requirements.
6 These final setting loads could be set via either a
7 mechanical shear stud (not shown) when set
8 mechanically or via final hydraulic pressure when
9 set with hydraulics. The seal setting piston would
10 be maintained in the set position via locking the
11 hydraulics in place for a hydraulic set or with
12 slips or a ratchet mechanism for mechanical sets.
13
14 For retrieval of the plug, the seals would be de-
15 activated via releasing the hydraulic pressure or by
16 releasing the ratchet/slip mechanism.
17
18 For high differential pressures, the setting force
19 would be sufficiently high to swage the casing with
20 the single seal assembly, thereby key seating the
21 seal assembly into the well delivering a large
22 resistance to movement up or down the well.

1 CLAIMS:-

2

3 1. An apparatus for securing a tubular member
4 within a liner or borehole, the apparatus comprising
5 at least one seal means associated with the tubular
6 member, and a pressure control means operable to
7 increase the pressure within the tubular member,
8 such that operation of the pressure control means
9 causes the tubular member to move radially outwardly
10 to bear against the inner surface of the liner or
11 borehole wall.

12

13 2. Apparatus according to Claim 1, wherein the
14 apparatus comprises a pair of seal means, and
15 apparatus is arranged such that the pressure is
16 increased within the tubular member between the pair
17 of seal means.

18

19 3. Apparatus according to either of claims 1 or 2,
20 wherein the tubular member is moved radially
21 outwardly such that the tubular member undergoes
22 elastic deformation and also plastic deformation.

23

24 4. Apparatus according to claim 2 or to claim 3
25 when dependent on claim 2, wherein the apparatus
26 further comprises a body located co-axially within
27 the tubular member and the pair of seal means are
28 mounted upon the body and are selectively energised
29 to seal against the inner surface of the tubular
30 member.

31

- 1 5. Apparatus according to any preceding claim
2 wherein one end of the tubular member is provided
3 with hoop strain reduction means.
4
- 5 6. Apparatus according to any preceding claim,
6 wherein at least one of the liner and tubular member
7 is provided with a surface that facilitates
8 providing engagement between the liner and the
9 tubular member.
10
- 11 7. A method of securing a tubular member within a
12 liner or borehole of a well, the method comprising:-
13 inserting the tubular member into the borehole;
14 and increasing the pressure within the tubular
15 member between a pair of seal means associated with
16 the tubular member, such that the pressure increase
17 causes the tubular member to move radially outwardly
18 to bear against the inner surface of the liner or
19 borehole.
20
- 21 8. A method according to claim 7, further
22 comprising inserting the tubular member into the
23 liner or borehole to the required depth by way of
24 one of wireline, coil tubing and drill pipe.
25
- 26 9. A method according to either of claims 7 or 8,
27 wherein the tubular member is moved radially
28 outwardly such that the tubular member undergoes
29 elastic deformation and also plastic deformation.
30
- 31 10. A method according to any of claims 7 to 9,
32 wherein at least one of the liner and the tubular

1 member is provided with a surface that facilitates
2 providing engagement between the liner and the
3 tubular member.

4

5 11. A method according to claims 7 to 10, wherein a
6 metal to metal seal is formed between the outer
7 circumference of the tubular member and the inner
8 circumference of the liner.

9

10 12. An apparatus for securing a first tubular
11 member to a second tubular member already located
12 within a liner of borehole of a well, the apparatus
13 comprising:-

14 a pair of seal means associated with one of the
15 first and second tubular members;

16 and a pressure control means operable to
17 increase the pressure within one of the first and
18 second tubular members between the pair of seal
19 means;

20 such that operation of the pressure control
21 means causes one of the first and second tubular
22 members to move radially to bear against a surface
23 of the other of the first and second tubular
24 members;

25 such that at least one of the first and second
26 tubular members undergo elastic deformation and also
27 plastic deformation.

28

29 13. An apparatus according to claim 11, wherein the
30 pair of seal means are mounted on a body member
31 which are capable of alignment downhole with one or

1 more profiles formed on a surface of the first
2 tubular member.

3

4 14. Apparatus according to claim 12, wherein the
5 pair of seal means are longitudinally spaced apart
6 on the body member and the pair of seal means are
7 arranged such that they are spaced further apart
8 than the longitudinal extent of the one or more
9 profiles.

10

11 15. Apparatus according to either of claims 13 or
12 14, wherein the pair of seal means are capable of
13 actuation to seal against the inner bore of the
14 second tubular member, and the body member is
15 provided with one or more fluid ports or apertures
16 formed in its sidewall, such that a fluid is capable
17 of being pumped through the first tubular member,
18 through the one or more fluid ports and into a
19 chamber defined between the outer surface of the
20 body member, the inner bore of the first tubular
21 member and the pair of seal means.

22

23 16. A method of securing a first tubular member to
24 a second tubular member already located within a
25 liner or borehole of a well, the method comprising:-
26 inserting the first tubular member into the
27 borehole such that a lower end thereof is in close
28 proximity with an upper end of the second tubular
29 member; and
30 increasing the pressure within one of the first and
31 second tubular members between a pair of seal means
32 associated with one of the first and second tubular

1 members, such that the pressure increase causes one
2 of the first and second tubular members to move
3 radially to bear against a surface of the other of
4 the first and second tubular members, wherein at
5 least one of the first and second tubular members
6 undergo elastic deformation and also plastic
7 deformation.

8
9 17. A method according to claim 16, wherein the
10 pair of seal means are mounted on a body member
11 which is lowered into the wellbore through the first
12 tubular member by an elongate member and is further
13 lowered into the second tubular member.

14
15 18. A method according to either of claims 16 or
16 17, wherein the pair of seal means are
17 longitudinally spaced apart on the body member and
18 the pair of seal means are arranged such that they
19 are spaced further apart than the longitudinal
20 extent of the one or more profiles, and the body
21 member is lowered into the first tubular member
22 until the pair of seal means straddle the one or
23 more profiles.

24
25 19. A method according to any of claims 16 to 18,
26 wherein the pair of seal means are actuated to seal
27 against the inner bore of the second tubular member.

28
29 20. A method according to any of claims 16 to 19,
30 wherein a fluid is used to provide the pressure and
31 the fluid is pumped through the first tubular
32 member, through one or more fluid ports provided in

1 a sidewall of the body member and into a chamber
2 defined between the outer surface of the body
3 member, the inner bore of the first tubular member
4 and the pair of seal means.

5
6 21. A method according to claim 22, wherein once
7 the pressure has increased to a sufficient level,
8 one or more circumferential portions of the first
9 tubular member are expanded into a respective number
10 of the one or more profiles of the second tubular
11 member to form a joint between the first tubular
12 member and the second tubular member.

13
14 22. A sealing device for use in an annular space,
15 where the sealing device comprises:-

16 at least one substantially cylindrical inner
17 element;

18 at least one seal assembly; and

19 a displacement means operable to apply a force
20 on the said seal assembly;

21 where the said inner element comprises a wedge
22 member, and the said seal assembly is slidable over
23 the wedge member along the longitudinal direction of
24 the inner element, wherein the said seal assembly
25 expands radially outward when forced over the wedge
26 member;

27 the seal assembly comprising a radially
28 expandable annular seal supported by at least one
29 radially expandable support sleeve;

30 characterised in that the support sleeve forms
31 a substantially continuous support surface towards

1 the said annular seal in both expanded and non-
2 expanded positions.

3

4 23. A sealing device according to claim 22, wherein
5 the support sleeve comprises fingers supporting the
6 said annular seal.

7

8 24. A sealing device according to claim 23, wherein
9 the support sleeve comprises at least two types of
10 fingers.

11

12 25. A sealing device according to any of claims 22
13 to 24, wherein the sealing device comprises two
14 radially expandable support sleeves.

15

16 26. A sealing device according to any of claims 23
17 to 25, wherein the displacement means is disposed
18 between the said inner element and the said seal
19 assembly and the fingers are connected to an end of
20 their respective support sleeve.

21

22 27. A sealing device according to claim 24, wherein
23 the first type of finger comprises a generally
24 triangular support member, the end surface of which
25 defines a support surface and the second type of
26 finger preferably comprises a generally triangular
27 support member being generally T-shaped seen from
28 above, the end of which defines a support surface,
29 where the other side of the support member defines a
30 support surface.

31

- 1 28. A sealing device according to claim 27, wherein
2 every second finger of the support sleeve is of the
3 first type of finger, or the second type of finger
4 respectively.
5
- 6 29. A sealing device according to claim 28, wherein
7 the support surfaces of the second type of fingers
8 in a running in hole position rest on at least some
9 of the support surfaces of the first type of
10 fingers.
11
- 12 30. A sealing device according to any of claims 22
13 to 29, wherein there are at least two sealing
14 devices connected by means of a mandrel.
15
- 16 31. A sealing device according to any of claims 22
17 to 30, wherein an isolation plug is provided which
18 comprises one sealing device which is run into a
19 downhole well on an elongate member.
20
- 21 32. An isolation plug for plugging a downhole
22 tubular, the isolation plug comprising a sealing
23 device according to any of claims 22 to 31 and a
24 seal actuation mechanism, the seal actuation
25 mechanism being operable to expand the annular seal
26 radially outwards toward the downhole tubular to
27 firstly seal against an inner bore thereof and
28 secondly elastically and furthermore plastically
29 deform the downhole tubular.
30
- 31 33. An isolation plug according to claim 32,
32 wherein a seal setting piston is attached to a

1 mandrel which protrudes through an upper end of the
2 isolation plug and the mandrel is attached to a
3 setting tool, such that when, in use, the mandrel is
4 pulled upwards against a sleeve mounted against the
5 upper end of the isolation plug, the seal means is
6 activated and is extruded outwardly to contact the
7 downhole tubular.

8
9 34. A method of plugging a downhole tubular
10 comprising inserting an isolation plug into the
11 downhole tubular to a desired location and expanding
12 a seal means of the isolation plug in a radially
13 outwards direction toward the downhole tubular by
14 operating a seal actuation mechanism of the
15 isolation plug such that the seal means firstly
16 seals against an inner bore of the downhole tubular
17 and secondly elastically and furthermore plastically
18 deforms the downhole tubular.

19
20 35. A method of providing a downhole metal to metal
21 seal between two concentrically arranged tubulars,
22 comprising the steps of:-

23
24 a) expanding radially outwardly the innermost
25 tubular through elastic and then plastic deformation
26 until it contacts the inner bore of the second
27 tubular; and

28
29 b) continued expansion of the first tubular such
30 that it firstly elastically and secondly plastically
31 expands the second tubular radially outwardly.



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53

Examiner: Mr Rob Lynch

Claims searched: 1-21

Date of search: 6 May 2004

Patents Act 1977: Search Report under Section 17

Documents considered to be relevant:

Category	Relevant to claims	Identity of document and passage or figure of particular reference
X	1 - 4, 7 - 10, 12, 13, 16, 17, 19, 20 & 21	EP 0937861 A3 (Halliburton Energy Services, Inc.) See whole document, especially figure 3 and paragraphs 38 & 39, noting liner 122, and seal means 202 & 204
X,E	1, 2, 4, 6 - 8, 10 & 11	WO 2004/015241 A1 (Baker Hughes Incorporated) See whole document, especially abstract and figures, noting especially seals 36, 38, and expanding tubular section 52.
X	1, 2, 4, 6 - 8 & 10	EP1165933 A1 (G.E.I.E. EMC) See abstract, figures and lines 22 - 34 of column 3 noting especially seals 11
X	1, 2, 4, 6 - 8 & 10	US2002/0020524 A1 (Halliburton Energy Services, Inc.) See figures and paragraphs 5 - 11, noting seals 131

Categories:

X Document indicating lack of novelty or inventive step	A Document indicating technological background and/or state of the art.
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Field of Search:

Search of GB, EP, WO & US patent documents classified in the following areas of the UKC^W:

E1F

Worldwide search of patent documents classified in the following areas of the IPC⁰⁷

E21B

The following online and other databases have been used in the preparation of this search report

Online: EPODOC, WPI, PAJ, OPTICS